Technologies for Balancing Electrical Energy and Power

5

Having discussed the need for balancing electrical energy and power with additional technologies that can provide load adaption, transport of electricity from abroad, or storage of electricity, the following chapter provides an overview of technological options. Section 5.1 develops a classification scheme. Individual technologies are discussed in Sects. 5.2, 5.3 and 5.4, following the differentiation of "storage" technologies providing ways from "electricity to electricity", "electricity to anything" and "anything to electricity". Section 5.5 summarises options for demand response and demand-side management, including the bundling of individual technologies. The analysis in Sect. 5.6 reveals the life cycle costs of individual storage technologies. These are discussed in the context of different specific tasks involved in balancing energy and power. A central requirement for a system with a high penetration of renewable electricity suppliers and balancing capabilities is the viability of various technologies. Therefore, Sect. 5.7 analyses, to the extent possible, the future viability of relevant technologies. The environmental effects, resource use and system characteristics according to the indicators derived in Sect. 2.2 are considered.

5.1 Classification of Energy Storage Systems and Systems Offering Positive and Negative Control Power

Storing energy requires specific technologies, which are in general neither cheap nor efficient. Therefore, it is crucial to analyse the different options for storing energy in detail and to select appropriate technologies with regard to demand. The purpose of storage systems is to supply positive and negative control power on different time scales. The term "storage" will be used here to describe a system that can supply positive and/or negative control power to the grid and includes also technologies beyond the classical storage systems, which take up electrical energy and supply electrical energy.

Certain storage technologies can be used for various applications. For comparison of storage technologies from an economic and technical point of view it is of

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relevance to define the application of storage technologies appropriately. Different classifications are necessary to specify the storage system application. Three different classifications with three classes each can be defined as follows:

A. type and location of storage systems,
B. duration and frequency of power supply,
C. input and output type of energy to and from the storage system.

Class A differentiates the placement of the storage systems and the main objective for its installation. The classes are

A1. modular storage systems with double use,
A2. modular storage for grid use only,
A3. centralised storage systems.

"Modular storage" describes those technologies that are made from relatively small basic units. The basic units can be connected together to form larger systems, but neither the efficiency nor the specific costs are reduced significantly when storage system size is increased. Typically, there are no special requirements concerning the location of such batteries other than certain safety issues.

In contrast, "centralised storage" technologies are those that are localised at specific sites and have specific requirements concerning the geological structure of the site (e.g., pumped hydro storage systems with two water basins on different levels). Furthermore, these technologies are typically characterised by the fact that efficiency increases while specific costs related to power and energy capacity decrease with increasing system size. Typical systems have an installed power of 100 MW or more.

"Double use" indicates that the main purpose for the installation of the storage system is not to supply grid services. The storage systems are installed to serve in a certain application, e.g., such as mobility. Batteries in electric vehicles can be used additionally for grid services, but their main objective is to assure mobility. These storage systems are different, because first of all the operation schemes must take into account their limited availability for grid services, on the other hand, however, these storage systems are typically already financed by their main application. Therefore, the storage systems can serve grid services additionally, but they need not refinance themselves from grid services only.

Class B has the following sub-classes:

B1. "seconds to minutes" – short-term energy storage,
B2. "daily storage" – medium-term energy storage,
B3. "weekly to monthly storage" – long-term energy storage.

The "short-term energy storage systems" have to supply their energy immediately after it is asked for. Full power is already supplied after a few seconds for a maximum duration of about a quarter of an hour. This allows these storage systems to supply primary control power to the grid or to serve as intermediate storage systems in applications with a high frequency of load changes. The latter could be, for example, cranes, which lift heavy loads, or acceleration and braking systems of trams and subways. The short-term energy storage systems have an energy to power ratio (installed capacity in kWh divided by the peak power in kW – E2P) of less than 0.25 h. Therefore, the storage systems must be capable of high power charging

and discharging and – depending on the application – they can be subject to a huge number of charge/discharge cycles per day.

The “medium-term energy storage systems” have an E2P ratio of 1–10 h and therefore the specific load on the storage systems is significantly less. Furthermore, the number of full cycles per day is very limited and rarely exceeds two full cycles a day. These storage systems make it possible to level differences in power generation consumption over the course of a day. Classically, such storage systems are charged during the night and supply additional power to the grid during peak load times (noon and late afternoon/early evening). These storage systems can also smooth out deviations between forecasted renewable power generation and actual generation. In contrast, “medium-term” storage systems cannot assure supply security if insufficient power generation from renewable sources occurs for prolonged periods of several days or weeks.

To ensure supply security in such circumstances requires “long-term energy storage systems”. Systems with E2P ratios of 50–500 can supply energy for several days or weeks. Therefore, automatically, the number of cycles per year is very limited. This requires very cheap storage media to allow a refinancing of the storage system. In addition, the self-discharge of such systems should be low.

Finally, “inputs and outputs of energy to and from the storage system” can be categorised as follows:

C1. “electricity to electricity” – positive and negative control energy,
C2. “anything to electricity” – positive control energy,
C3. “electricity to anything” – negative control energy.

The classification follows the strict definition of “storage systems” as elements in the power supply system, which can supply positive or negative control energy. According to this definition, “electricity to electricity” storage systems can supply positive and negative control energy to the grid. They take electricity from the grid to get charged and they supply electricity to the grid if needed. This is what typically is called a storage system. However, power or negative control energy could be served also by other technologies.

“Anything to electricity” technologies support the grid with positive control energy either by shutting down electrical loads, which for the grid is the same as increased power generation capacities, or by supplying additional power to the grids from energy reserves stored otherwise. The latter category includes all conventional power plants, which can supply positive control energy for different periods of time from fossil, nuclear, hydro or biomass fuels. Controlled shutdown of loads can be supplied, for example, by demand-side management strategies or by controlling the charging of electric vehicles.

“Electricity to anything” technologies use electrical energy and convert it into an energy carrier with a lower exergy level. The exergy level could be as low as zero, which is equivalent to the shutdown of a renewable power generator. However, the category also includes the generation of heat from electricity or the generation of chemical fuels from electricity, such as hydrogen or methane.

A combination of an “anything to electricity” and an “electricity to anything” storage technology can provide the same services to the grid as an “electricity to

electricity" storage system. Therefore, it is necessary to compare these technologies with regard to costs and technical potential. In addition, several other points must be taken into account when judging different storage technologies. The most relevant aspects are:

- investment costs,
- life cycle costs (LCC),
- environmental life cycle analysis (LCA),
- construction constrains,
- overall energy efficiency,
- overall impact on power supply system,
- CO_2 emissions,
- national energy autonomy,
- social and political acceptance.

The various available technologies are listed in Tables 5.1, 5.2 and 5.3, based on the three main categories discussed above.

Generally, all technologies belonging to a certain "duration and frequency" category ("seconds to minutes", "daily" or "weekly to monthly") are in direct competition to each other. By intelligent management, the modular storage systems can provide the same services to the grid as the centralised storage technologies.

5.2 Technical Description of "Electricity to Electricity" Energy Storage Technologies for a Balanced Electrical Energy and Power Supply

This chapter discusses the different technical options for balancing the power supply and power demand in the grid. First, the different storage technologies for electrical energy are discussed. The technologies are classified as found in Table 5.1.

Before looking at the different storage technologies in detail, it is worth having a look at the typical energy densities achieved with different classes of storage technologies. The comparison shows that chemical storage systems have, beside some options of heat storage, by far the highest energy densities, particularly when stored as liquids (Table 5.4).

5.2.1 "Mechanical" Storage Systems for Electric Power

Central storage systems typically have an installed power of more than 100 MW and typically are connected to high or extra high-voltage grids.

5.2.1.1 Compressed Air Energy Storage (CAES)

Compressed air energy storage systems use power to compress air and store it under high pressure. If power is needed from the storage system, turbines generate electricity by depressing the compressed air. Compressed air storage systems can

Table 5.1 Classification of electrical energy storage systems (positive and negative control power)

"Electricity to electricity" storage systems only			Typical time scale/energy-to-power (E2P) ratio		
			"Seconds-to-minutes" storage systems <0.25 h	"Daily" storage systems 1–10 h	"Weekly to monthly" storage systems 50–500 h
Type of construction/typical power	Modular storage systems with double use	1 kW–1 MW	– electric and plug-in hybrid vehicles with bi-directional charger – grid-connected PV-battery systems (e.g. lead-acid, lithium-ion, NaS, redox-flow, zinc-bromine batteries)	– electric and plug-in hybrid vehicles with bi-directional charger – grid-connected PV-battery systems (e.g. lead-acid, lithium-ion, NaS, redox-flow, zinc-bromine batteries)	
	Modular storage technologies for grid control only	1 kW–100 MW	– flywheels – (lead-acid batteries) – NiCd/NiMH batteries – EDLC ("SuperCaps") – lithium-ion batteries	– lead-acid batteries – NaS batteries – redox-flow batteries – zinc-bromine flow batteries – lithium-ion batteries	– redox-flow batteries (?)
	Centralised storage technologies	100 MW–1 GW		– compressed air (diabatic or adiabatic) – pumped hydro	– hydrogen – pumped hydro

Table 5.2 Classification of technologies for positive control power only

"Anything to electricity" positive control power			Typical time scale/energy-to-power (E2P) ratio		
			"Seconds-to-minutes" storage systems <0.25 h	"Daily" storage systems 1–10 h	"Weekly to monthly" storage systems 50–500 h
Type of construction/typical power	Modular storage systems with double use	1 kW–1 MW	– shut down of electric vehicles and PHEV charging	– CHP units with thermal storage – demand side management (DSM) of electrical loads (shut down) – electric vehicles and PHEV (stop charging)	
	Modular storage technologies for grid control only	1 kW–100 MW		– bio-gas power plants	– bio-gas power plants
	Centralised storage technologies	100 MW–1 GW	– rotating masses and steam reserve of conventional power plants	– gas power plants – coal power plants – hydro storage – solar thermal power plants with heat storage	– lignite power plants – nuclear power plants – hydro storage

Table 5.3 Classification of technologies for negative control power only

"Electricity to anything" negative control power			Typical time scale/energy-to-power (E2P) ratio		
			"Seconds-to-minutes" storage systems <0.25 h	"Daily" storage systems 1–10 h	"Weekly to monthly" storage systems 50–500 h
Type of construction/typical power	Modular storage systems with double use	1 kW–1 MW	– electric domestic house heating or cooling incl. heat pumps – demand side management (household and industry) – cooling devices – electric vehicles and PHEV with uni-directional charger	– electric domestic house heating or cooling incl. heat pumps – demand side management (household and industry) – cooling devices – electric vehicles and PHEV with uni-directional charger	
	Modular storage technologies for grid control only	1 kW–100 MW	– shut down of renewable power generators (wind, PV)	– hydrogen for direct use (e.g. in the traffic sector) – methane or methanol made from CO_2 and hydrogen – shut down of renewable power generators (wind, PV)	– hydrogen for direct use (e.g. in the traffic sector) – methane or methanol made from CO_2 and hydrogen
	Centralised storage technologies	100 MW–1 GW		– hydrogen for direct use (e.g. in the traffic sector) – methane or methanol made from CO_2 and hydrogen	– hydrogen for direct use (e.g. in the traffic sector) – methane or methanol made from CO_2 and hydrogen

Table 5.4 Overview of volumetric energy densities of different storage technologies (first order approximations)

Storage type	Volumetric energy densities [kWh/m^3]
Mechanical energy storage	
Potential energy (e.g., pumped hydro with 360 m height difference)	~1
Kinetic energy (e.g., flywheels)	~1
Electrical storage	
Electrostatic fields (capacitors)	~10
Electromagnetic fields (coils)	~10
Heat storage	
Sensible heat (e.g., water @ $\Delta T = 100$ K)	116
Phase changes (e.g., water to steam)	636
Chemical storage systems	
Lithium-ion batteries	~300
Liquid hydrogen	~2,400
Gasoline	~12,000

have additional heat storage (adiabatic CAES) or they can use the heat needed during expansion of the air to avoid icing on the turbines from a conventional natural gas-fired turbine (diabatic CAES). The latter can achieve efficiencies in the order of 55% because the compression heat gets lost. Adiabatic CAES with high temperature heat storage can achieve efficiencies of up to 70%. (It should be noted that they are still, however, in the R&D phase; no real-size system has yet been deployed.) The losses are high due to heat generation during compression of the air. The compressed air is typically stored in underground caverns. Especially caved salt domes are an interesting technical and economical solution. However, this also restricts possible locations for CAES to areas with an appropriate geological formation for the air storage. Germany has many salt domes in its northern regions. This coincides well with the major potentials for wind power. Two diabatic CAES are in operation worldwide, several major utilities plan demonstration plants with adiabatic CAES in Germany for 2016–2018. According to Table 5.1, CAES are centralised "daily" storage systems.

5.2.1.2 Pumped Hydropower Plants

Pumped hydropower plants are today the backbone of the power grid and provide almost all the storage capacity used in the power grid. Water flows between an upper storage lake and a lower reserve basin either by natural gravity through turbines (during power generation for positive control power) or by pumps (when consuming energy and storing it in the upper storage lake for negative control power). The upper lakes are either natural lakes with natural feeders or artificial lakes that are only supplied by pumped water. A typically sized pumped hydropower station using an artificial lake can provide full power for about 8 h either in the one or the other direction. The power generation can be controlled continuously

over a wide power range. In older systems the pumps can hardly be controlled. They either work or they do not. To adapt the power to the required negative control power, the pumped hydropower station can either use different available pumps or the power station generates, in parallel, power to adjust the net power consumption ("water short circuit"). This results in relative low efficiencies. With the newest technologies for the motor, pump and power electronics, it is possible to adjust the pumping power continuously and to reach an efficiency level of around 80%.

Typically, pumped hydropower stations are used today for levelling the difference between predicted and actual power profiles as well as for energy trading. This usually involves buying cheap energy from the grid during the night and selling it back during the peak load hours of the daytime. The systems with artificial lakes without natural feeders typically are sized to serve peak power for about 8 h. This size is, however, far from sufficient for supplying power during periods when there are several days of low wind speed. This would require significantly larger water reservoirs than are available today at lakes with dams and natural feeders. These existing systems would need a retrofit with pumps to become pumped hydro storage systems. An important question is how to get access to a sufficiently large water basin if no lower lake is available. Long caved pressure tunnels might be a solution, but it would be necessary to analyse the options in each case in detail with regard to the cost effectiveness. According to Table 5.1, pumped hydropower plants are centralised "daily" or "weekly to monthly" storage systems.

5.2.1.3 Hydro Storage Systems

Huge hydro storage plants with natural feeders can be used also for levelling the power grid especially for longer periods of time. This can be achieved by an optimised operation strategy and would require additional turbines, but no pumps, and, therefore, no lower water basin. The optimised strategy would be to generate power only during long-lasting periods when there is insufficient power generation from fluctuating renewables. During other periods, the systems do not generate power or only small quantities, e.g., to assure a minimum water flow in the downstream rivers. As this reduces the number of operating hours even though the amount of water from the natural feeders remains the same, it is necessary to increase the installed power. This option is especially relevant in conjunction with very large hydro storage systems in Scandinavia and the Alps. As can be seen in Table 5.2, hydro storage systems are centralised "daily" or "monthly to weekly" storage systems for positive control power.

5.2.1.4 Flywheels

Flywheels store energy as kinetic energy in rotating bodies. The ability of flywheels to store energy is, thus, proportional to the second power of the rotational speed and the moment of inertia of the rotating body. Three different technologies are on the market today. They can be grouped according to the rotational speed: slow rotating flywheels with approximately 5,000 revolutions per minute (rpm), medium rotational speeds with approximately 25,000 rpm, and fast rotating flywheels with approximately 100,000 rpm. However, increasing the rotational speed does not

necessarily result in a higher level of stored energy, because the radius of the rotating bodies must be reduced with increasing rotational speed. Otherwise the materials of the rotating bodies could not withstand the centrifugal forces. For the medium and fast rotating flywheels, complex composite materials are applied, as also used, for example, in modern aircrafts. Flywheels in power storage systems have no mechanical coupling. The flywheel is accelerated by means of an electric motor, which is used in the case of discharge as a generator.

Flywheels are classic high power storage devices, which can deliver very high power for short periods of time. This is very similar to electrochemical double-layer capacitors. The power rating of the flywheels only depends on sizing of the power electronics and the installed electro motor/generator. The number of lifetime cycles is almost unlimited. A major disadvantage of flywheels is the high self-discharge rate. This is due to losses in bearings and the friction of the rotating body. Therefore, vacuum housing and low-friction bearings are used. Depending on the product, it takes several hours for the flywheels to lose 50% of their stored energy. If high numbers of charge/discharge cycles are performed per day, this is not of major relevance, but flywheels are inefficient with regard to long-term energy storage.

Table 5.1 categorises flywheels as a modular storage technology for use as "power" storage systems.

5.2.2 "Electrical" Storage Systems for Electric Power

5.2.2.1 Electrochemical Double-Layer Capacitors ("Supercaps")

Electrochemical double-layer capacitors (EDLC) fill the gap between classical capacitors used in power electronics or filters with their almost infinite cycle lifetime and rechargeable batteries with orders of magnitude higher energy density. EDLCs are often called "supercaps" even though this is originally a brand name. EDLCs combine properties from the world of capacitors and electrochemical devices. Energy is stored purely in electric static fields. However, the EDLCs have liquid electrolytes and they use ions for forming the second "plate" of the capacitor. One plate is made from a highly porous carbon material with a very high internal surface and the counter electrode is formed on this active surface by the ions dissolved in the electrolyte. During discharge, the ions move away from the carbon surface. No electrochemical reaction occurs in the cell in normal operation. The energy storage process is simply a physical movement of ions to the surface or away from it. This is the reason for very long cycle lifetimes in the order of a half to one million cycles. It is a system using liquid electrolyte. The liquid electrolyte is not 100% stable and is dissolved on the carbon surface. The reaction rate of this process is strongly correlated with temperature and voltage. The lifetime of EDLCs depends on operating conditions, but is in any case limited. Energy densities of commercial products are typically in the order of 4–6 Wh/kg, however the power density is very high and can go beyond 10 kW/kg. Together with the high cycle lifetime, this qualifies the technology for applications with a very high power demand for short periods of time, but at high cycle numbers. Typical discharge

times should be in the order of 10s. Therefore, EDLCs can be used, for instance, in hybrid electric applications to support combustion engines during acceleration or for regenerative braking. Besides their low energy density, EDLCs are quite expensive. Prices for EDLCs are in the order of 10,000 €/kWh. Therefore, areas of applications for EDLCs in the power grid are mainly for power quality stability rather than for storing significant amounts of electrical energy.

In Table 5.1, EDLCs are designated as modular storage technologies used for "power" storage systems.

5.2.2.2 Superconducting Coils

While capacitors store electrical energy in an electrostatic field, coils in general store electrical energy in electro-dynamic fields. The stored energy depends on the current flowing in the coils. As losses are proportional to the current squared, industrial applications of coils as energy storage devices make sense only in cases of superconducting coils. Superconductivity results in zero resistance of the conductors and therefore no losses occur during storage in the coil itself. However, a very deep temperature is required, either below 4 K for classic superconducting materials or in the range of 30–80 K for high-temperature superconducting materials that require either liquid helium or liquid nitrogen. To keep the fluids liquid, a continuous operation of the cooling systems is required and ultimately this produces losses.

Even though superconducting coils are an interesting technology from a scientific point of view, it is hardly possible to envision commercial applications in the field of energy storage systems with significant amounts of stored energy as discussed in this study. Therefore, this technology is not listed in Table 5.1.

5.2.3 "Chemical" Storage Systems for Electric Power

5.2.3.1 Lead-Acid Batteries

Lead-acid battery technology is the electrochemical storage technology with the highest installed capacity worldwide. Many different applications, such as starter batteries in vehicles in combustions engines, uninterruptible power supplies, fork-lift trucks or traction applications, are served with lead-acid batteries. Several large-scale battery systems in the range of some 10 MW and up to 50 MWh have been installed in the past based on lead-acid batteries.

Lead-acid batteries are made mainly from lead, sulphuric acid and plastics. The energy density of approximately 25–35 Wh/kg is low, while the energy efficiency of 80–90% is fair. Stationary lead-acid batteries of high quality can achieve lifetimes of 6–12 years and cycle lifetimes of 2,000, and also, in special cases, more than 7,000 equivalent full cycles. Costs per kWh are today in the order of 100–250 €/kWh for the battery cells depending on the quality. Industrial batteries have recycling quotas near 100%. The secondary lead can be used again for battery production. Two different main technologies are used today: flooded lead-acid batteries with liquid electrolyte and valve-regulated lead-acid (VRLA) batteries

with internal gas recombination. While the VRLA batteries require significantly reduced maintenance efforts and lower requirements with regard to the ventilation of the battery compartments, batteries with liquid electrolyte achieve longer cycle lifetimes in stationary applications.

Large-scale battery systems based on lead-acid batteries have been erected around the world to solve local power quality and power supply problems. This includes battery systems for the stabilisation of grid extension, or frequency stabilisation. The largest battery system, which has been operated in Germany, was the BEWAG system in Berlin. The system was put into operation in 1986 in Berlin with an installed power of 17 MW and 14 MWh energy capacity. This system was used for frequency stabilisation in the island grid of West Berlin. The energy throughput of the battery was almost three times the nominal capacity, or more than 7,000 equivalent full cycles in almost 7 years or operation. Several more similar systems were planned, however, due to German reunification and the connection of the power system of West Berlin to the UCTE grid, the additional systems were not necessary after 1990.

Lead-acid batteries have low energy density, low power density and a limited lifetime, but the basic material costs are very low and therefore the technology will retain a dominating position in the stationary battery market in the coming years.

According to Table 5.1, lead-acid battery technology is a modular "power" which can be used in the "seconds to minutes" range, but preferably is used as a "daily" storage system.

5.2.3.2 High Temperature Sodium-Based Batteries

Sodium-nickel chloride ($NaNiCl_2$, also called the ZEBRA battery) and sodium-sulphur (NaS) batteries are different compared with other battery technologies, due to the high operating temperature of around 300°C. These batteries use a solid-state electrolyte with sodium-ion conduction. The active masses are either liquid (sodium or sulphur) or solid with an additional liquid electrolyte ($NiCl_2$). If the batteries cool down, an operation is no longer possible. The number of thermal cycles should stay as small as possible to avoid thermo-mechanical stress. To maintain the temperature it is necessary to compensate the heat losses. This can be achieved either by cycling the batteries, which generates heat due to the internal losses, or by heating the batteries. Typically, the temperature can be maintained quite easily if the battery runs one cycle a day. A commercial 16 kWh ZEBRA battery pack with thermal insulation has a heat loss of approximately 100 W. While the ZEBRA battery is used these days mainly for mobile applications, such as electric vehicles or busses, the NaS battery is used only in stationary applications.

NaS batteries are the most promising technology for stationary large-scale battery storage systems. The cycle lifetime is in the range of 10,000 cycles and the specific costs for the materials are very low. Especially in Japan, several battery systems for grid support in the range of several MW and up to 50 MWh have been installed and are in operation. The main challenges are the solid-state electrolytes for Na^+-conductivity, the gaskets, overall battery management and safety issues.

According to Table 5.1, NaS batteries are modular "daily" storage systems.

5.2.3.3 Lithium-Ion Batteries

Lithium-ion batteries have their origin in portable applications such as laptops, mobile phones or PDAs. Lithium-ion batteries have the highest energy density (more than 200 Wh/kg) among all rechargeable battery technologies and show also very high efficiencies in the range of 90–95%. These efficiencies are unique among all electrical energy storage systems in addition to electrochemical double-layer capacitors. Lithium-ion batteries also can achieve very high power densities.

Lithium-ion battery technology is a manifold technology where many different material combinations are used. Various cathode and anode materials, as well as separators and electrolyte formulations, allow the creation of batteries with a wide range of performance characteristics with regards to energy density, power density, safety, cycle and calendar lifetime, as well as high or low temperature performance. The huge number of material combinations results also in a very dynamic development of new and improved battery systems. Many companies follow different material combinations. There is, as of yet, no favourite material combination or cell design for future lithium-ion technologies. Beyond the markets for portable applications and power tools, electro-mobility is the main driver behind the development of lithium-ion battery technology. Improvements in cell technology and economy of scale effects caused by the automotive market also support the introduction of lithium-ion batteries in stationary applications. A special focus is currently on the double use of the batteries from electric vehicles for driving and for grid support. Lithium-ion batteries show sufficient cycle lifetime to also work for load-levelling or other grid service applications, in addition to normal driving.

The main challenges of the lithium-ion batteries are safety issues and costs. For the automotive sector, a price reduction for electric vehicle batteries down to approximately 200 €/kWh is estimated for mass production towards 2020. For stationary applications, costs can decrease by maybe another 20% or so due to lower requirements with regard to cooling or energy density. Lithium-ion batteries are especially competitive compared with lead-acid batteries for discharge times below 1 h. This is due to the fact that lithium-ion batteries can deliver almost 100% of their capacity even at high current rates, while lead-acid batteries can only deliver about one third of their capacity at high current rates.

In Table 5.1, lithium-ion batteries are designated as a modular storage technology preferred for use for "power", but also for "daily" storage systems.

5.2.3.4 Nickel Cadmium (NiCd) and Nickel-Metal-Hydride (NiMH) Batteries

Like lead-acid batteries, NiCd battery technology is a traditional battery technology. NiCd batteries have a high mechanical robustness and achieve cycle lifetime in the range of several 1,000 full cycles. Furthermore, they have the best deep temperature performance of all rechargeable battery technologies. A downside is that NiCd batteries are significantly more expensive and have a lower efficiency compared with lead-acid batteries. Besides cost and efficiency concerns, the toxic cadmium contained in the batteries is a major obstacle for their further market penetration and use in stationary battery markets. Even though today one of the

largest battery storage systems in operation in Alaska (40 MW peak, 6.5 MWh within a 15 min discharge) is made from NiCd battery cells, it is expected that this technology might be replaced by lithium-ion batteries in the coming two decades.

NiMH batteries have been developed to replace the use of toxic cadmium. The resulting NiMH technology has a better energy density and better power performance. In the last decade, it has become the leading technology for hybrid electric vehicles. Several hundred thousand hybrid vehicles, especially from Japanese car manufacturers, are equipped with NiMH batteries. However, the basic material costs are high and therefore there are significant cost reductions that would be necessary for large-scale stationary applications. These would be hard to achieve. Therefore, NiMH will remain mainly a technology for mobile applications.

According to Table 5.1, NiCd and NiMH batteries are primarily modular storage technologies or "power" storage systems.

5.2.3.5 Redox-Flow Batteries

Redox-flow batteries are different from conventional batteries because their active materials are dissolved in the charged and the discharged state in a liquid solution. Typically these salts are diluted in a solvent, also called the electrolyte.[1] The dissolved active materials are stored in tanks and are pumped continuously or on demand into a reaction unit where the electrochemical charge/discharge process takes place. The reaction unit itself consists of structures on which surfaces the reduction or oxidation of the dissolved ions takes place, with current collectors and a membrane as the electrolyte and separator. The general concept is quite similar to reversible fuels cells and therefore the technology is sometimes called the "liquid fuel cell". The total charge/discharge efficiency of redox-flow batteries can be in the order of 75% and is, therefore, almost twice as high as for hydrogen storage systems.

As the solubility of the ions in the solution is limited, the energy density of the most popular vanadium redox-flow battery systems is on the order of the lead-acid battery. However, their big advantage is that the energy capacity of such a battery can be scaled very easily by increasing the tanks, while the power rating of a redox-flow battery is scaled by the size of the stack. Thus, energy capacity and power rating can be scaled independently of each other.

As mentioned before, vanadium is the most popular material for redox-flow batteries. As vanadium is stable in sulphuric acid as the solvent in four different oxidation states, it can be used for both electrodes. On the one electrode V^{2+}/V^{3+} is used, while the other electrode uses V^{4+}/V^{5+}. If the battery is fully charge, only V^{2+} and V^{5+} are present, in the fully discharged state it is V^{3+} and V^{4+}. The open

[1] From a systematic point of view, the solvent is not the electrolyte (even though these terms are used frequently). The function of an electrolyte is to couple the electrodes of an electrochemical system as an ion conductor and at the same time as an insulator for electrons. In redox-flow batteries this is the membrane in the stack that separates the liquid active materials of the positive and the negative electrode.

circuit voltage is about 1.2 V. Other interesting material combinations are, for example, Fe/Cr, Br_2/Cr or NaBr + Na_2S_4/Na_2S_2 + $NaBr_3$ (Regenesys). However, no mature products with materials other than vanadium are on the market. A major technical challenge so far is the permeability of the membrane for the active material ions. If the active materials mix, the battery loses its ability for storing electrical energy. Due to the fact that vanadium is used on both electrodes, this is not of major concern for the vanadium redox-flow battery. A problem for vanadium is that it is relatively expensive and therefore not an appropriate material to achieve the very low costs, which would be necessary to make the redox-flow battery more than a daily storage system. Cycle lifetimes in the order of 10,000 cycles have been demonstrated. This is the level that would be needed for practical purposes. Special focus must be put on the conventional part of the system, including the tank, the temperature control and the piping. Another problem is that leakages are quite common. More positively, recycling of the active materials of redox-flow batteries is quite simple and efficient.

Zinc-bromine batteries are also listed as redox-flow batteries. But, even though the electrodes are also liquid in the charged state, this is not the case for both electrodes after discharging. Zinc is plated during discharging as metallic zinc in the electrode and therefore the stack can discharge only a limited amount of materials. After a certain capacity throughput, the stack is simply filled with zinc. An independent sizing of energy capacity and power rating is therefore not possible. This technology is not suited for discharge times of more than some hours and the zinc-bromine battery should therefore not really be seen as a member of the class of redox-flow batteries.

In Table 5.1, redox-flow batteries are categorised as modular "daily" or – maybe in the future – "weekly to monthly" storage systems, if new material combinations are found.

5.2.3.6 Hydrogen Storage Systems

Hydrogen for energy storage has two main characteristics: a low efficiency of 25–40% (electrical power to hydrogen to electrical power) and very low specific costs for storage capacity. The hydrogen is generated by electrolysers. Various technologies are available, working either at moderate temperatures around 60°C or in the range of 1,000°C, or which can be operated directly at higher pressure levels between 30 and 200 bar to avoid additional external mechanical compressors. The reconversion of hydrogen to electric power can be done either by fuel cells or hydrogen turbines. Storage systems in the range of several 100 MW will most likely have hydrogen turbines rather than fuel cells.

The costs are lowest if caved salt caverns are used for storing hydrogen at pressures of 50–200 bar. Costs for caving salt caverns are in the order of 40 €/m^3. They will inevitably vary for different locations, depending on the local geological conditions and depending on the distance to the sea for draining the salty water. Very low investment costs of less than 0.50 €/kWh (see equation below) can be achieved according to the following assumptions: hydrogen pressure in full charged conditions is 100 and 50 bar have to remain for the cushion gas (gas which

must remain in the cavern to maintain a sufficient pressure), a thermal energy of hydrogen of 3.5 kWh/Nm^3, and an efficiency of 50% for the conversion of hydrogen to electric power.

$$\text{Specific investment costs} = \frac{40\,\frac{€}{m^3}}{(100bar - 50bar) \cdot 50\% \cdot 3.5\,\frac{kWh}{Nm^3}} = 46\,\frac{€ct}{kWh} \tag{5.1}$$

Compared with electrochemical battery technologies with investments costs not below 100 €/kWh, the investment costs for hydrogen storage systems are very small. Therefore hydrogen is, aside from hydropower, the only storage technology that is suited for long-term storage. However, the economy of hydrogen systems depends mainly on the costs for the electric power during the charging process. Due to the low overall efficiency, at least 2.5 kWh electric power must be purchased for 1 kWh of delivered electric power. The business plans of such storage systems depend mainly on assumptions for the electric power price. Some people assume electric power costs to be zero in periods of excess energy from renewable energy systems, because variable costs tend towards zero. If very low electricity costs for charging the hydrogen storage systems can be achieved, this technology becomes very interesting. However, renewable energy systems have very high fixed costs and therefore the total revenues must be calculated for achieving an economic operation. The assumption of zero costs for excess power periods means that power must be sold at higher prices during other periods to assure the refinancing of the system.

The technical potential for hydrogen storage systems is huge. The cavern of the diabatic compressed air energy storage of the Huntdorf plant in Germany with 300,000 m^3 volume filled with hydrogen instead of compressed air results in a storage capacity at 100 bar of 26 GWh (assuming 50% conversion efficiency to electricity and 50 bar remaining gas pressure for maintaining sufficient pressure). The pumped hydropower plants in Germany together feature a capacity of about 40 GWh in total. This shows the huge capacity of even a single storage system. Current natural gas storage systems that are used in Germany for the national reserve have a capacity of 20 billion m^3 in 44 storage systems. Using this storage capacity for hydrogen for electrical power results in 35 TWh of available electrical power. This is sufficient to supply the electric power consumption of Germany for approximately 21 days.

According to Table 5.1, hydrogen storage systems are centralised “weekly to monthly” storage systems.

Additional downstream technologies based on hydrogen production are also the synthesis of, for example, CH_4 or methanol. Both require CO_2, either from concentrated sources or from the air. This allows using the energy also as a gas or liquid fuel in other applications. Reconverting the fuels into electricity only makes sense in decentralised CHP units with additional heat usage. Otherwise, the additional losses from synthesising CH_4 or methanol (efficiency is in the order of 80% , starting from hydrogen) just add to the total losses of the system. However, this could be a good option for serving the transport sector with fuels from renewable energies.

Table 5.3 notes that CH_4 or methanol from renewable hydrogen can be produced in modular or in centralised storage systems and can function as "electricity to anything" technologies, which can be used for "daily" or "weekly to monthly" storage systems.

5.3 Technical Description and Potential of "Electricity to Anything" Energy Storage Technologies for a Balanced Electrical Energy and Power Supply

Apart from the measures of using peak load power stations (thermal power stations) or storage options to balance the fluctuating feed-in from renewable energy sources, the demand side can also be influenced in the form of load management in order to contribute to balancing (Grimm 2007). The increased integration of fluctuating feed-in plants (wind, sun) by all means permits a change from demand-oriented power supply to a generation-oriented power supply. Strategies for generation-oriented power supply and, thus, for influencing demand must be investigated and evaluated with regard to an equally possible central solution.

Demand-side management (DSM) and demand response (DR) provide the potential to shift decentralised loads of end customers, such as private, commercial or industry customers, according to their requirements. An electronic marketplace, as developed in the framework of the German E-Energy projects, could serve the end customer here as the necessary communication and interaction platform for the marketing of its power flexibilities.

The loads can be influenced by two different mechanisms in principle. On the one hand, the end customer can react manually to suitable incentives (e.g., price signals) (demand response). This concerns all electrical devices of the end customer. On the other hand, an automated load control is conceivable for such devices, the deferred use and modulated operation mode of which entail no loss of comfort, economic consequences or restrictions in everyday household/business life (dispensable loads) (demand-side management). Since the manual customer reaction of the first mechanism cannot be assessed at present,[2] the analysis concentrates on the potentials of an automated load control.

In the following, the industrial sector (which, as expected, has the highest potentials for load shifting), the future area of electrical mobility and the household sector (white goods (washing machines, dishwashers, tumble dryers), electromobile and heat pumps) are analysed with regard to a possible contribution for adjusting the load to the fluctuating feed-in. Suitable shiftable loads are identified and then evaluated. Moreover, a first estimation is given for the inclusion of the CHP plants with a maximum power of 10 MW in a demand-side management approach.

[2] In the framework of the E-DeMa project, more detailed findings on this are expected, based on the experiences of a 9-month field test in 2012.

5.3.1 DSM Industrial Sector

Klobasa (2007) examines the load management potentials of the electricity-intensive industry. Klobasa's result was based on the following sectors for the provision of power flexibilities: cement industry, paper industry, cross-sectional technology (air-conditioning), nutrition (cold storage houses), basic chemicals, nonferrous metals and metal production.

The maximum shiftable power is the maximum power that can be disconnected or connected in one moment in a branch of industry. A total load management potential of approximately 3 GW results for 1 day for all industries. This is an estimation for the whole of Germany; the regional and geographical concentration and distribution of individual industries' load management potentials has not been considered.

As special contract customers, most of the described potentials of the industry are already being used. Different terms of delivery and more differentiated tariffs apply for industry customers in principle, meaning power suppliers already recognise saving and power shifting potentials and negotiate contractual conditions with customers accordingly. It can therefore not be expected that the concentration of power suppliers on the industry sectors will strongly increase. Klobasa (2007) also indicates that the potentials in the industry will not decisively change in the coming years. These values are therefore assumed as constant for the years looked at: 2020, 2030 and 2040. The only exception is the aluminium industry. For this branch of industry, which is essentially equipped with high load shifting potential, observers of the industry assume that a large portion of the generation capacity will be moved abroad by 2020. The main reason for this is the high price for primary energy in Germany. Because of this, a decrease in the shifting potential by more than 70%, from the current approximately 0.3 GW to less than 0.1 GW, is assumed in this segment (Klobasa 2007).

In conclusion, by necessity, this section was based on findings from a single reference; further detailed investigation is lacking. The estimation of the load management potential of industrial loads is an open topic for investigation and discussion.

5.3.2 Balance Provision by Electrical Mobility

The estimation of electric vehicles' potential for the provision of balancing energy is derived from the analysis of the load profiles that would result in the case of an uninfluenced charging behaviour. These load profiles were drawn up from real passenger car movement patterns and are described in more detail in Rehtanz and Rolink (2009). Figure 5.1 represents the average load curve, standardised for a single passenger car on a working day with uninfluenced charging and a load power of 3.7 kW (Rehtanz and Rolink 2009). Depending on the charging infrastructure, different scenarios result. Either the vehicles are charged at home only (home) or also at work (home and work) or additionally in public places (wide-area).

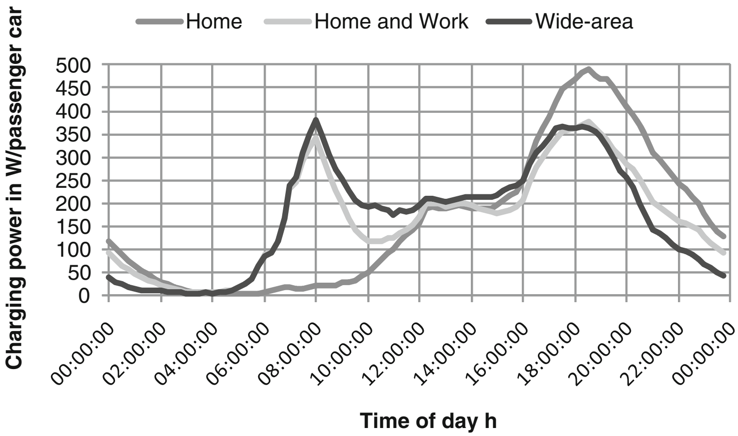

Fig. 5.1 Daily load curves of electric vehicles

The following basic assumptions apply for all three scenarios. The day range per vehicle is limited to a maximum of 100 km. The battery storage of the vehicles is to be sufficient for the complete daily mobility requirement (on average, approximately 30 km). This precondition makes an almost free deferral of the charging possible during the day. The energy consumption of the vehicles is 20 kWh/100 km. Furthermore, it is assumed that the vehicles are only charged starting from a resting duration of a minimum of 1 h. This number is taken, because for shorter parking times, the effort of plugging in the car is too high. If this time is reduced to 15 min, there is only a little impact on the resulting curves.

As can be seen in Fig. 5.1, the vehicles are largely charged in the morning at around 04:00 h in all three scenarios if the charging behaviour is uninfluenced.

As can be seen from Fig. 5.1, a release (peak load) of up to 350–500 MW is possible with one million electrical vehicles for 1–2 h. This value varies, however, in the course of the day, and the condition at least has to be fulfilled that all vehicles are charged at a certain point in time, e.g., at 05:00 h in the morning. Since the charging times can be shifted over the course of a day, a further effect can be obtained for adjusting consumption to energy provision, although a consistent load management must be developed for this.

Unlike conventional and large household loads (e.g., those of white goods), the power requirement of the electric vehicles rises in the course of the day.

5.3.3 DSM Household Sector

5.3.3.1 Technical Potential of DSM in the Household Sector

In principle, an end customer is designated as a household customer. The Energy Industry Act (EnWG) defines an end customer as one who has an electricity consumption of less than 10,000 kWh/a.

A demand-side management model is used for the calculations used in estimating the load shifting potentials in the household sector (Kreutz et al. 2010). The target function of the DSM model consists of smoothing the residual load curve described in Sect. 4.1.1.1 on a transport network level. This leads to the residual load, which still has to be covered with fossil power stations that can provide a smaller fluctuation range in the course of the day and hence, a smoother curve. For this, less (expensive) peak load power stations or storage systems have to be used.

When selecting suitable electrical appliances in the household for an automated load control, two criteria must be fulfilled:

– The appliance must have a sufficient annual energy consumption and a significant power consumption.
– A shift in operation must be accepted by the end customer.

For private and commercial customers, load control measures can be an issue. Possible acceptance of consumers must be considered. This applies in particular for the areas of lighting, TV/audio and cooking. Cooling and freezing appliances take up 19% of the average electricity consumption of a household, although these appliances only briefly require power when operating the compressor and have a very low consumption otherwise. Besides, the energy efficiency of these devices would be impaired by these measures.

So-called white goods take up 15% of the electricity consumption in households. Shifting the operation of these loads is much easier to justify than with the groups of appliances described previously. Of course, the electricity requirement depends on the living and customary habits of the end customers. This depends on the numbers of washing machines, dishwashers and tumble dryers operated, the frequency of use and the program sequencing applied (Gaul 2009).

In accordance with the investigations in Gaul (2009), a use probability distribution per day and a program sequence have been specified for the respective groups of white goods. No interruptions in the program sequence are envisaged in the simulation, since this would result in a reduction in energy efficiency. Shifting the load therefore means shifting the starting time of the washing, rinsing or drying program. In Table 5.5 the equipment, the frequency of the use and the electricity consumption for white goods are indicated.

Since current studies (see Chap. 3) forecast a significant rise of heat pumps and these have a relatively high energy consumption, these consumers are also included in the calculations. Regarding acceptance, it is to be expected that the end customers have no objections to load management of personal heat pumps, as long as the

Table 5.5 Assumptions for DSM – white goods (2020, 2030 and period 2040+)[a]

	Equipment level [%]	Use per day [%]	Electricity consumption per program sequence [kWh]
Washing machine	93	48	0.9
Tumble dryer	38	25	2.5
Dishwasher	62	40	0.7

[a] No program interruption after starting

consumer's heat requirement is covered. For the modelling of the daily load curve, load profiles standardised to an energy consumption of 1,000 kWh/a are used, depending on the season. So while the heat pumps run 24 h a day in winter and in the transition periods as planned, they are only used during the day in summer, between 06:00 and 22:00 h. Following the current procedure of the distribution network operator with regard to heat pumps, demand-side management is simulated daily by up to three cut-off times of 2 h each for load reduction. As a boundary condition, it is taken into account that at least 2 h pass between two cut-off times.

The following assumptions were set for heat pumps in the context of DSM:

– Forecast of annual electricity consumption of all heat pumps in Germany:
  • 2020: 4.4 TWh (Nitsch and Wenzel 2009),
  • 2030: 6.1 TWh (Nitsch and Wenzel 2009),
  • 2040+: 6.4 TWh,
– Annual electricity consumption per heat pump: 6,000 kWh,
– Maximum electrical power per heat pump: 2 kW.

The electric vehicles to be integrated into the network in the future are also modelled as electrical consumers. As regards the number of electric vehicles, an increase from the one million electric vehicles required in 2020 to 20 million electric vehicles in the period 2040+ is assumed. It is assumed that the electric vehicles' introduction to the market will be successful and that demand for them is high. For the estimation of the effect of DSM in the case of electric vehicles, the uninfluenced load curve, as well as the assumptions and considerations, were set, as described in more detail in Sect. 5.3.2. The two scenarios political RES and lead scenario (see Chap. 3) are taken as a basis for the model calculations. One average day and three extreme days are looked at for each of the years 2020, 2030 and 2040+. It is assumed in the consideration that there are no time or capacity-related restrictions in the load shifting, i.e., that all electrical loads specified above are fully available at the time when they are to be shifted and the end customers show the highest flexibility and acceptance.

The DSM is iterated. First, the cut-off times for the heat pumps are considered, since it is assumed that the end customer is not affected by the control measure. The resulting residual load then serves as a basis for the second step, the load shift of the electric vehicles. Finally, the white goods are shifted in order to fill the valleys of the residual load curve as far as possible, which the first two steps could not fill. Optimising prioritisation would be possible as part of advanced investigations.

An exemplary representation for the starting situation of the DSM model, Fig. 5.2 shows the uninfluenced feed-in of renewable energy and the expected total load curve for Germany for the lead scenario 2040+. The data above makes clear how high each controllable load group's power demand ratio in each quarter of an hour is to the total load. The high number of renewable energy conversion plants in the case of the lead scenario for 2040+ is responsible for the fact that there are times in the course of the day where feed-in supply is above the load demand.

Figure 5.3 shows the result of the DSM simulation for the lead scenario 2040+. Compared with Fig. 5.2, the loads are moved into time slots where there is too much feed-in from renewable energy sources at the times where the load demand was

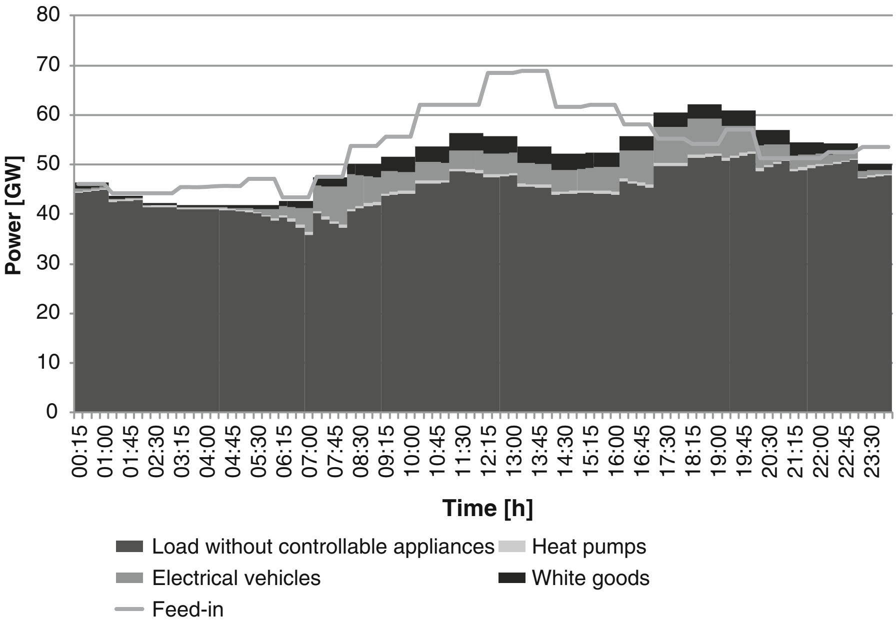

Fig. 5.2 Feed-in of renewable energy and load curve in Germany for lead scenario 2040+ without DSM

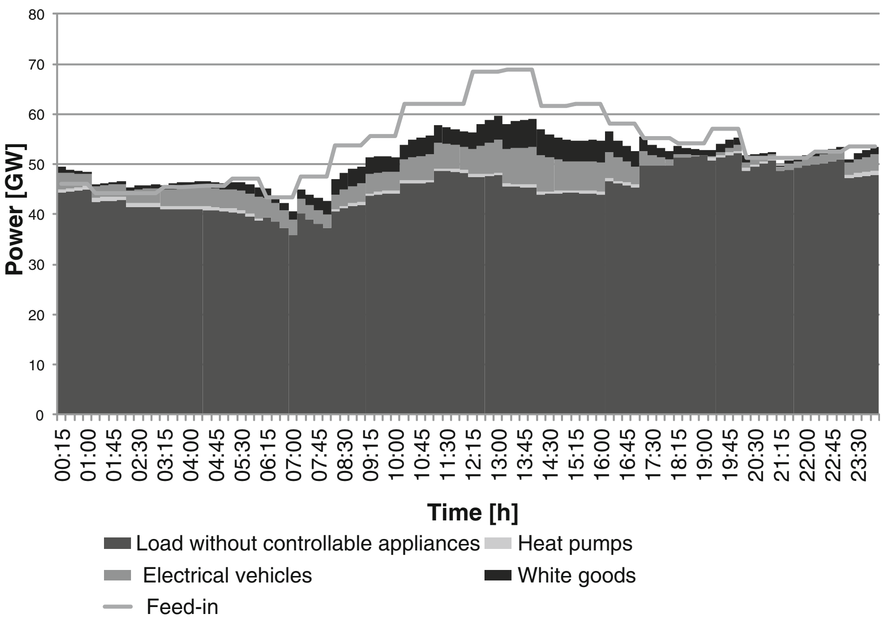

Fig. 5.3 Feed-in of renewable energy and load curve in Germany for the lead scenario 2040+ with DSM

Table 5.6 Maximum shifting potential of residual load for average days of political RES and lead scenario

		ΔP_{max} [GW]
2020	Lead scenario	3.0
	Political RES scenario	3.0
2030	Lead scenario	4.3
	Political RES scenario	5.0
2040+	Lead scenario	7.5

higher than the regenerative feed-in. This example also makes it clear that the load requirement of Germany is too small for the peak feed-in times, meaning that there are still times where storage systems have to be filled or additional energy exported. As a last resort, if the storage systems need to be filled and no export is possible, the power stations using renewable energy sources have to be shut down.

In Table 5.6, the parameter ΔP_{max} describes the maximum, simultaneous lowering of the peak load for the two scenarios – political RES and lead scenario – for the years 2020, 2030 and 2040+. The power use of heat pumps, electric vehicles and white goods, reaches its maximum at ΔP_{max}.

The shifting potential ΔP_{max} will prospectively increase from 3 GW up to 7.5 GW in the scenario 2040+ due to the increasing use of heat pumps and electric vehicles from 2020 onwards. The calculation assumes a complete shiftability of loads in the course of a day; however, due to user restrictions in the course of a day it is to be assumed that the real usable potential is only about half as great. This difference can only be exploited if the DSM mechanisms, including down to individual devices, run smoothly in an automated and user-friendly manner.

It has been shown that the DSM in the household sector can, on the assumptions made, contribute to a levelling of the energy balance on a transport network level during one day. Load shifts are only carried out here on a distribution network level. This makes it important to investigate the change in the degree of simultaneity due to the load shift in order to prevent an overload situation in the distribution network (see Sect. 6.1). Important secondary considerations in DSM are network capacities and the ability to ensure power supply.

The expected economic effects of using DSM must also be looked at in detail (see Sect. 5.3.3.2).

5.3.3.2 Expected Economic Benefits from DSM in the Household Sector

For the lead scenario in 2030 and 2040+ in particular, where the renewable feed-in exceeds the network load in some instances, it is determined, alongside the maximum shifting potential of the residual load (see Sect. 5.3.3.1), how large the energy quantity is which is shifted by the DSM at times where there is an energy oversupply. It is possible to indicate the proportion of feed-in of renewable energy that can additionally be used by DSM ("RES additional use"). This value refers to the total feed-in of renewable energy. This percentage proportion provides information related to the smaller feed-in of fossil power stations when using

DSM. In order to determine the percentage change to the generation costs as well as to the CO_2 emissions caused by DSM in the household sector, a model that determines the hourly employment of conventional power stations for 12 typical days of a year (working days, Saturdays and Sundays across four seasons) is used (see Waniek et al. 2008). Based on the consideration of the hourly load curve found within a "typical" day, power station restrictions, such as minimum operating and shutdown durations as well as the start-up costs resulting from this, can also be considered. The power station database on which the model is based includes all larger power stations installed in Germany today (approximately 370) and has been supplemented and adapted accordingly for future scenarios. Apart from the information on the type of fuel, year of construction and installed power, the network node of the network model used in Chap. 6 is also allocated to each power station. Thus, the simulation of the power station employment also provides the node-specific feed-in and feed-outs necessary for the network calculations. The market model is based on the assumption that the marginal costs are the decisive influence on bidder behaviour. Peak pricing effects, i.e., strategic bidder behaviour in situations of shortage, are not taken into consideration. This means that the value of peak load plants is underestimated. However, since this in turn affects all technologies looked at, such as peak load power stations, storage systems or load management in equal manner, no significant fault occurs in the comparison of the technologies. Table 5.7 contains the results of the model calculations for the political RES and the lead scenario in the case where there are no underlying time or capacity restrictions for the load shifting (see Sect. 5.3.3).

The following points can be stated as substantial trends:

– In the lead scenario in 2030 and 2040+ in which a high amount of regenerative electricity cannot be consumed in the system, applying DSM allows for the additional use of 0.7% and 1.5% of the feed-in of renewable energy, respectively. These precise proportions do not have to be generated by the conventional power stations.
– The generation costs can be reduced by DSM. The largest savings are approximately 14% in 2040+.
– Besides the positive effects, an increase in CO_2 emissions is determined in the scenarios until 2040+. The reason for this is that base load power stations are increasingly used when smoothing the residual load, which leads to increased

Table 5.7 Parameters for the average days of the political RES and lead scenario for 2020, 2030 and 2040+

		ΔP_{max} [GW]	Additional use of RES [%]	Δ generation costs [%]	ΔCO_2 emission [%]
2020	Lead scenario	3.0	–	−2.4	3.4
	Political RES scenario	3.0	–	−1.1	0.2
2030	Lead scenario	4.3	0.7	−2.7	4.4
	Political RES scenario	5.0	–	0.1	1.3
2040+	Lead scenario	7.5	1.5	−13.9	−7.5

CO_2 emissions in the case of a power station mix with brown and hard coal. A CO_2 reduction is obtained through the changed composition of the base load in the scenario 2040+.

The model calculations show that the DSM by all means carries advantages in the household sector, such as the contribution to levelling out the energy balance on a transport network level and cost savings. In order to conclude the analysis of the household sector shifting potentials during a day, the reduced generation costs are to be compared with the additional costs for implementing demand-side management across Germany in the household sector.

The minimum requirement for the necessary infrastructure consists in transferring a control signal to a central place in the household based on the Institution of Load Management (aggregator), and then from there to the individual controllable devices. In principle, deriving a cost estimation requires differentiating between the outhouse infrastructure, which ensures transmission to the households, and the inhouse infrastructure. It is assumed that outhouse infrastructure will be available from 2020 onwards. The use of the power supply infrastructure (PLC) or the Internet is possible for this. The DSM does not entail marginal costs since existing systems can be used.

Things are different with inhouse communication. A communication module (gateway) is necessary as a central reception point for the control signal, which prepares the signal if necessary and transfers it to the controllable devices via PLC or radio technology, for example. If this technology is not present in a household, additional costs are incurred by the additional inhouse communication infrastructure required.

In the example scenario 2040+, generation cost savings of approximately 13% can be made with the DSM. This corresponds to an annual amount of approximately 650 million €. If the highest equipment level of the controllable appliances (93% of households are equipped with washing machines, and some households with additional white goods, heat pumps and electric vehicles) is considered, 37.2 million households would be eligible for a DSM. Accordingly, macroeconomic savings of approximately 18 € per year result for an individual household. However, this value can turn out to be higher due to peak pricing in the market, which cannot be modelled here. The technical implementation, consisting of investments in the necessary infrastructure and ongoing expenditure for contract management, accounting system and further operating costs necessary for executing a DSM, should therefore not exceed this amount. The customer may have comfort losses due to the DSM, meaning that a high acceptance is only to be assumed in the case of complete automation.

In conclusion, DSM mechanisms contribute to the balancing of demand that will be required in the future. The value of these mechanisms per household is very limited. If the estimated value of 18 € per year is compared to the electricity bill of an average household of around 1,000 € per year, of which around one-third is actual energy cost, it is obvious that a pure shift of consumption cannot create a value of around more than 10% and more likely of only 6% under this particular calculation. In the context of DSM and the management of electric vehicles,

communication between all the devices and the management entity (aggregator) is of crucial importance. Only with a standardised information and communication system (ICT system) for all the devices that have to managed could such a management scheme be efficiently set up in the future.

5.3.4 Shutdown of Renewable Power Generation

According to the classification of technologies that can provide negative control power to the grid found in Table 5.3, the shutdown of renewable power generators is also a technical option. This is possible for seconds to minutes or even for daily needs. In contrast with fuel-fired power plants, renewable power generators have almost no savings in costs if they are turned down to provide negative control power. Therefore, the costs for a shutdown are equivalent to the generation costs and are dominated by the depreciation of the investment. Nevertheless, the costs are clearly predictable and the shutdown of renewable power generators is very fast. The costs for a kWh not fed into the grid are more or less equivalent to the rate paid to the system operator according to the renewable feed-in law. While PV generators can reduce their power output within milliseconds, it takes some 10 s for a wind turbine to come to a standstill.

While regularly occurring events can be handled with storage systems, the shutdown of renewable power generators is especially an option for peak events. This option is essential from a technical, economic and legal point of view. Currently, wind turbines already have to reduce their power output if the grid is overloaded. There is no similar option when an imbalance in total power generation results in significantly negative prices at the power exchange. Generally, the negative prices at the power exchange should not exceed the value of the energy from renewable power generators determined by the renewable feed-in law. However, to implement such strategies, it would be necessary to develop appropriate procedures to determine the amount of energy that was not fed into the grid by the individual power generator. This is not a trivial exercise. It would most probably be necessary to use reference meteorological data for the region and an accepted technical characteristic for the power generation system to calculate the loss in energy generation.

5.3.5 Generation of Chemical Fuels such as Hydrogen, Methane or Methanol from Electricity

An increasing important topic of discussion is the use of chemical fuels as large-scale storage systems that can be fed into different sectors of energy consumption. Basically all approaches to the generation of chemical fuels are based on the generation of hydrogen as a first step. Therefore, the general assumptions found in Sect. 5.2.3.6 on hydrogen production are valid here as well.

It is worthwhile to discuss the advantages of chemical fuels. The general idea is to use existing infrastructures for the storage and distribution of fuels, either as gas or as liquid fuel. The total consumption of such fuels is very high. To get to a CO_2-free energy supply will require a substitution of fossil fuels by CO_2-neutral alternatives. Given that the potential storage capacity is huge, chemical fuels are an option that should be investigated.

The technical processes to produce fuels from hydrogen (or using hydrogen directly) are well known. It is necessary to keep in mind that the processes typically have an efficiency of around 80% based on hydrogen as a raw material. This is true only if a concentrated source of CO_2 is available, for example, from a conventional fossil fuel-fired power plant or from biomass power plants. If the CO_2 is taken from the air, the total efficiency is reduced by a factor of approximately 0.8. For the following analysis, the availability of concentrated CO_2 is assumed.

The advantage of liquid fuels such as methanol from renewable energies is their very high energy density compared with all other electrical storage technologies. For renewable methane (CH_4), there is the advantage of an existing infrastructure. Renewable methane can be distributed and used in the same way as natural gas. The main advantage of the concept is that production and usage of renewable fuels can be started without any additional infrastructural burden. Any size of production unit can be installed at any point in time to start the technology.

Nevertheless, the overall efficiency of renewable fuels is low, especially if they are used to reproduce electricity. The efficiency from electricity to electricity is hardly more than 30%. Therefore, renewable fuels should be generated only if all options for distributing the generated electric power via grids are used and if a pure hydrogen storage system with reconversion of hydrogen to electricity on site makes no practical sense.

Renewable fuels are, in addition to hydrogen and very large pumped hydro storage systems, one of the only options for monthly storage systems.

5.4 Technical Description of "Anything to Electricity" Energy Storage Technologies for a Balanced Electrical Energy and Power Supply

5.4.1 CHP Plants with Thermal Storage

The rising number of decentralised combined heat and power plants (CHP plants) offers the possibility of aggregating power from decentralised generation. Two different types of CHP plants are focused on: The μ-CHP plants with an electrical power generation of up to 10 kW and the local heat CHP plants for heating centres in combination with a local heat network with a maximum electrical power generation of 10 MW. The following assumptions and conditions form the basis for determining the shifting potentials:

– The μ-CHP plants looked at are run in monovalent operation and cannot be modulated but are subject to a clocking (connection and disconnection).

– The local heat CHP plants are run in modulated operation. In order to cover the increased heat requirement a peak load boiler is additionally used. This peak load boiler is able to monovalently supply the adjacent local heat network with heat energy (if the CHP plant is being maintained or repaired).
– All plants are heat-controlled and the heat requirement of the end customer must be covered at all times.
– All plants have a sufficiently dimensioned heat store.
– With both plant types, the associated heat store is completely filled in 4 h in full load operation and is also emptied in 4 h in the case of a high heat requirement.
– Due to the varying heat requirements over the course of a year, the results after the summer and winter seasons are differentiated.
– All plants can be coordinated centrally.

The shifting potentials of the plant types are determined separately and at first, on a pro rata basis, based on installed power. In addition, positive and negative shifting potential are differentiated. The positive shifting potential represents the amount by which the generation power can be increased. The negative shifting potential indicates the amount by which the generation power can be reduced. Finally, forecasts from studies are taken as a basis and used to determine future shifting potentials.

When stochastic mixing and clocking are taken as a basis, approximately 50% of the total installed power of all μ-CHP plants is available on a winter day. This means that approximately 50% of the μ-CHP plants are always in operation. Since the heat requirement is only given by hot water preparation in summer and since the μ-CHP plants are thus only rarely in operation during the day, a power portion of 5% of the installed power of all μ-CHP plants without coordination is assumed. If there is central coordination, a power percentage of 100% of the installed power of all μ-CHP plants is available for 4 h maximum on one winter and one summer day. With coordination in a negative direction it is also possible to lower the power of all μ-CHP plants to zero on a winter and a summer day.

A positive and negative power potential of 50% of the installed power of all μ-CHP plants results for one winter day. There is a very small power potential in a negative direction for a summer day, since the majority of the plants are not in operation at the same time (approximately 5%). With an appropriate coordination, the positive shifting potential amounts to 95% of the installed power of all μ-CHP plants. In both cases however, the time sequence for filling and emptying the store is to be considered.

When using the local heat CHP plants, it is necessary to determine, in a similar way to the μ-CHP plants, how high the proportion of the generation power of the local heat CHP plants is in relation to the installed power of all local heat CHP plants without coordination.

According to the dimensioning of the heating centre, the local heat CHP plants run continuously in winter without coordination and in full load operation. They are not subject to any clocking and are dimensioned in such a way that they cover the basic heat requirement of the relevant area. There is therefore no positive power potential in winter.

In a similar way to the μ-CHP plants, it is possible to set the generation of the local heat CHP plants to zero through coordination. There is a negative shifting potential of 100% of the total installed power of the local heat CHP plants in winter. It should be noted that this power can be available for a very long time, since the heat requirement is covered by an appropriate peak load boiler. It is nevertheless of interest to put the local heat CHP plant back into operation as soon as possible for reasons of economic efficiency.

In summer, the local heat CHP plants are not in operation due to the low heat requirement. This means there is no negative shifting potential. It is however possible for all local heat CHP plants to feed in at the same time by way of coordination. Thus, there is a positive shifting potential of 100% of the total installed power of the local heat CHP plants. This power can only be provided for 4 h, since the heat store is filled after 4 h.

In accordance with Nitsch (2008), the gross electricity generation of the μ-CHP and local heat CHP plants is 30 TWh in 2020 and about 41 TWh in 2040. A high use of biogas is to be assumed here. A rise to 45.5 TWh is assumed for 2040. In 2020, a total power from the decentralised CHP plants of 11 GW is assumed. The percentage rise of the gross electricity generation has been used as a basis for determining the installed power of 2030 and 2040. An installed power of 15 GW results for 2030 and of 17 GW for 2040+. However, these numbers strongly depend on the development of the building insulation, which has a high impact on the heat demand and on the heat-electricity ratio of the technology used.

In Table 5.8, the forecast gross electricity generation and installed power of μ-CHP plants and local heat CHP plants in Germany for 2020, 2030 and 2040+ is represented. It is to be noted here that the gross electricity generation in 2020 and the associated installed power from Nitsch (2008) suggest a very low average number of operation hours for the CHP plants.

Based on these values, it is assumed that the number of operation hours of the local heat CHP plants is twice as large as that of the μ-CHP plants. Accordingly, the power values P_{μ} and $P_{local\ heat}$ shown in the table result.

In the following tables, the shiftable power of the CHP plants in Germany determined above is presented. In Table 5.9, the amount by which generation power can be increased is indicated. This positive shifting potential is accompanied by the negative shifting potential, shown in Table 5.10. The negative shifting

Table 5.8 Forecast gross electricity generation and installed power from CHP (<10 MW) (Nitsch 2008)

	Gross electricity generation CHP plants [TWh]			Installed power CHP plants (GW)		
	μ CHP W_{μ}/TWh	Local heat CHP $W_{local\ heat}$/TWh	Total W_{ges}/TWh	μ CHP P_{μ}/GW	Local heat CHP $P_{local\ heat}$/GW	Total P_{ges}/GW
2020	11.0	19.0	30.0	6.0[a]	5.0[a]	11.0
2030	16.0	25.0	41.0	8.5[a]	6.5[a]	15.0[a]
2040+	18.0	27.5	45.5	10.0[a]	7.0[a]	17.0[a]

[a] This value is based on calculations, which in turn are based on the values from Nitsch (2008)

Table 5.9 Positive shifting potential of the CHP plants (<10 MW)

	Shifting potential μ CHP [GW]		Shifting potential Local heat CHP [GW]		Shifting potential μ and local heat CHP [GW]	
	Winter	Summer	Winter	Summer	Winter	Summer
2020	3.0	5.7	0	5.0	3.0	10.7
2030	4.25	8.1	0	6.5	4.3	14.6
2040+	5.0	9.5	0	7.0	5.0	16.5

Table 5.10 Negative shifting potential of the CHP plants (<10 MW)

	Shifting potential μ CHP [GW]		Shifting potential Local heat CHP [GW]		Shifting potential μ and local heat CHP [GW]	
	Winter	Summer	Winter	Summer	Winter	Summer
2020	3.0	0.3	5	0	8.0	0.3
2030	4.25	0.4	6.5	0	10.75	0.4
2040+	5	0.5	7	0	12	0.5

potential represents the amount power by which the generation power can be reduced. Both a winter and a summer day are shown.

The results indicate that only the μ-CHP plants can realise a positive shifting potential in winter. Since local heat CHP plants are in continuous operation in winter without coordination, there is no positive shifting potential during this time.

As the plants are only very rarely in operation in summer, a very high positive shifting potential can be reached on a summer day. Positive shifting potentials of 10.7, 14.6 and 16.5 GW are obtained in summer. Since the load peaks are observed in winter, however, coverage gaps in generation will more likely arise during the winter months.

Looking at Table 5.10, it becomes clear that there is a very large negative shifting potential in winter. In 2020 to 2040+, the total negative shifting potential rises from 8.0 to 12 GW. By contrast, a very small negative shifting potential is hit because of the low heat requirement in summer. The maximum value of the shifting potential in summer is 0.5 GW in the period 2040+.

As a concluding remark, it should be noted that in estimating maximum potential only winter and summer days were examined in this chapter. The transition periods offer possibilities for striking balances between positive and negative shifting potential. This means that a similar power value can be shifted both positively and negatively.

It should be stressed that the shifting potentials for the different years are hypothetical. The development of the CHP plants beyond 2020 is difficult to estimate, since the CHP plants up to an electrical power of 50 kW are currently only in the market introduction phase.

5.4.2 Conventional Power Plants Using Fossil, Nuclear, Hydro or Biofuels

According to Table 5.2, positive control energy can be supplied to the grid also from conventional power plants. In fact, today the primary control power comes almost completely from conventional power plants and through 24-h forward planning.

5.5 Conclusions on Options for Demand Response and Demand-Side Management

The power shifting potential of customer loads and distributed generation was estimated in the previous sections. Its management includes demand response, demand-side management and virtual power plants, which enable the shifting of distributed generation and load on a daily basis. Storage technologies that are applicable come from several classes of storage systems. Therefore, a separate analysis of all options is carried out in this section.

In order to compare and evaluate the sectors examined in Sects. 5.3.1–5.4.1, the most important parameters are summarised in Table 5.11. As regards the maximum shifting potential, it should be noted again that this really represents a maximum value, which is reached in the case of an above-average user acceptance. The values and evaluation in the table refer to the lead scenario 2040+, and thus to the period in which the new technologies will most probably be established and spread on the market.

Looking at Table 5.11, it becomes clear that implementing DSM offers the largest potential with CHP plants. With a positive shifting potential of 5 GW in winter and 16.5 GW in summer, and a negative shifting potential of 12 GW in winter, the maximum positive shifting potential is far above the potential of controllable devices. However, due to the load correlation, the winter value is more relevant as the CHP is used fully during cooling periods.

On the assumption that the number of electric vehicles will rise exponentially in the coming years and that the shifting potential across Germany will become very large because of this, it is important to include this sector in DSM. User acceptance

Table 5.11 Prioritisation of the individual sectors for the scenario 2040+

	Maximum shifting potential [GW]	User acceptance
Heat pumps	0.6	Very high
White goods	1.9	Low
Electric vehicles	6.0	High
Industrial loads	2.8	Very high
CHP (<10 MW)	+5/−12 (winter) +16.5/−0.5 (summer)	High

for electric vehicles is high as long as the car is not used. It is assumed, however, that the users do not want to be restricted in their driving behaviour.

The heat pumps will have a relatively small potential of 0.6 GW in future. Due to very high user acceptance, including heat pumps in DSM systems is seen as more important than including white goods.

White goods have a large shifting potential of 1.9 GW, but low user acceptance is assumed. White goods represent the greatest influence on user behaviour, and therefore it is assumed that they will be accepted by users only to a very limited extent. Due to restrictions in use and problems of acceptance, only half the potential that is technically possible is likely to be available in reality for electric vehicles and white goods.

Since DSM already exists to some extent for industrial loads with a potential of 2.8 GW, it is necessary to ensure that this DSM continues to be improved and that newly developed generation processes can be added if necessary. User acceptance exists thanks to relatively large financial incentives.

In total, the load shifting potential within a day is technically between 16.3 and 23.3 GW, but in real terms, considering user acceptance, probably less than 10 GW. A coverage contribution to the power gap of up to 35 GW in the scenario 2040+ must therefore be considered as a necessary option for future power system scenarios.

5.6 Life Cycle Cost Analysis of Storage Technologies

Several storage technologies have been discussed, however, based on the given information it is almost impossible to choose “the best” technology. Several parameters define the performance of a storage technology and they are very different in nature and therefore difficult to rate against each other.

The following table shows and describes the parameters that need to be defined for each storage technology. The parameters need to be adjusted to each other. For instance, for a high-quality device, high cost and long lifetimes can be an optimum choice, but a low-cost version with short lifetime might also be suitable.

In fact, even more parameters must be taken into account for the cost calculation, such as costs for purchasing land, a building for the system or the suitable temperature range. These costs are not taken into account here, because they are either extremely site dependent (land) or will appear more or less in the same way for all technologies (building). For stationary applications, the temperature is typically not that important because the storage systems are operated under well-controlled conditions. Other aspects such as recyclability or limitation of resources are important parameters for judging the suitability of a storage technology. They are discussed in Sect. 5.7. However, they are of minor importance for an individual business decision if a new storage system is planned.

However, a comparison of technologies can be made only if the application itself is well defined and the optimum parameters and options for a specific storage

Table 5.12 Parameters defining a storage technology

Parameter	Unit	Description
Costs per installed capacity	€/kWh	Defined per kWh of total installed capacity (independent from the net usage of the storage system)
Calendar lifetime of storage system	Years	Lifetime until the storage system itself needs replacement
Costs per installed power	€/kW	Includes all costs attributed to power related devices, such as inverters or generators The costs for the components needed during charging and during discharging can be different
Calendar lifetime of power-related components	Years	Lifetime until the power-related elements need replacement The lifetime for the components needed during charging and during discharging can be different
Efficiency	%	Three different efficiency values must be distinguished: – Charging efficiency (grid to storage) – Storage efficiency (possible losses in the storage, e.g., for gas compression) – Discharging efficiency (storage to grid) All are defined as the ratio of energy coming out of the process to energy going into the process. All auxiliary consumers are included
Self-discharge	%/month	Energy losses related to the installed storage capacity while the energy is stored
Depth of discharge (DOD)	%	Percentage of used capacity in day-to-day operation
Cycle lifetime of the storage system	#	Number of cycles at the defined DOD that can be achieved in a constant cycling mode
Maintenance and repair costs	%/year	Costs related to the total investment costs for keeping the system in perfect condition. Does not include the replacement costs for a component at the end of its lifetime

technology according to Table 5.12 are chosen. Storage applications need to be defined by the parameters listed in Table 5.13.

Taking all these aspects into account, a first order approximation makes it possible to calculate the costs of the storage system expressed as €ct/kWh for power fed into the grid from the storage system. The calculated value is the amount of money that must be earned while selling power to the grid. It does not include the cost of buying the energy that can be sold to the grid.

Based on this methodology, it is possible to compare the different storage technologies along all relevant aspects. Low efficiency, for example, is taken into account through the costs for buying the energy that is needed for the losses. Lifetimes of storage technologies are also taken into account.

The methodology has not been developed to find out whether the storage system can be operated on an economical basis. This would require analysing not only costs but also the possible income that can be achieved with the system. For a given system definition, according to Table 5.13, the earnings should be independent from

Table 5.13 Parameters defining a storage application

Parameter	Unit	Description
Charging power	kW	Defines the required power at which the storage systems can be charged
Discharging power	kW	Defines the required power at which the storage system can be discharged
Available energy from the storage system	kWh	Defines how much energy can be supplied from the storage system to an application
Cycles per day	#/day	Defines how often per day the available energy from the storage system will be discharged (used)
System lifetime	Years	Required period for which the storage system should be operated
Capital costs	%	Capital cost rate used for the annuity calculation: the difference between the expected capital return rate and the inflation rate
Electricity costs	€ct/kWh	Average rate at which the storage system buys electricity. The electricity costs are needed to calculate the operational costs of the storage systems, namely the energy which is getting lost in the efficiency chain of the system

Table 5.14 Reference cases for an economic comparison of different storage technologies

Reference case	Short description	Charging power = discharging power	Available energy	Cycles per day
Long-term storage ("weekly to monthly storage")	Energy storage for long periods with almost no wind energy (200 h operation at full power in both directions)	500 MW	100 GWh	0.06 (1.5 cycles per month)
Load levelling in the transport grid ("daily storage")	Typical design of existing large-scale pumped hydropower stations (e.g., Goldisthal)	1 GW	8 GWh	1
Peak shaving in the LV grid ("daily storage")	Storage system for peak shaving and load levelling	100 kW	250 kWh	2

the specific storage technology. The methodology is mainly developed to compare storage technologies from the classes "daily storage" and "weekly to monthly storage" according to Sect. 5.1.

Such a comparison of storage technologies has been performed in the framework of the VDE/ETG study (Bünger et al. 2009). Some exemplary results from this study are discussed in the following paragraphs. Three different reference cases according to Table 5.14 will be discussed. Only some preselected technologies are analysed for the different reference cases.

The width of the bars in the graphs (Figs. 5.4, 5.5, 5.6) represents the expected cost reduction potential starting at today's costs and ending where specialists expect the costs to be in about 10 years' time, assuming a very strong market growth. The data basis comes from literature studies and expert knowledge. The cost reduction potential is based on existing and demonstrated technologies and does not assume

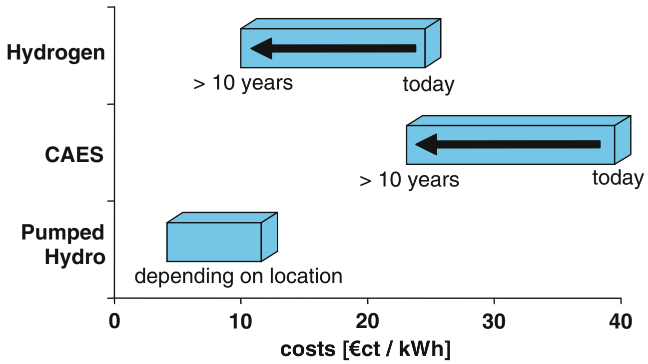

Fig. 5.4 Comparison of life cycle costs per delivered kWh for the reference case "long-term storage" (system lifetime 40 years, capital costs 8%, electricity costs 4 €ct/kWh)

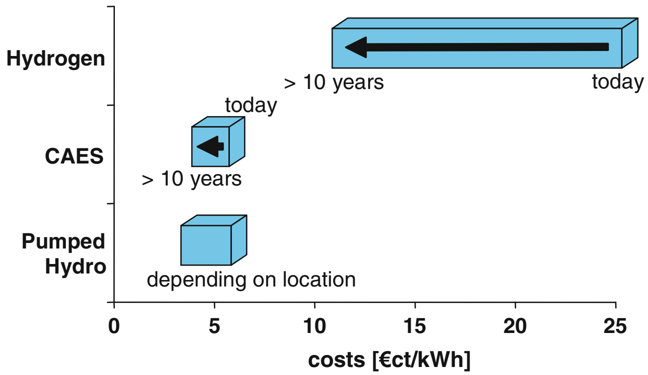

Fig. 5.5 Comparison of life cycle costs per delivered kWh for the reference case "load levelling in the transport grid" (system lifetime 40 years, capital costs 8%, electricity costs 4 €ct/kWh)

totally new developments. For the established technologies, the bandwidth is smaller than for those technologies that just come onto the market. Finally, the left-hand end of the bar represents the costs that could be achieved assuming sound technological development and taking into account economy-of-scale effects.

For the reference case "long-term storage", only pumped hydro storage systems reveal relatively low costs (Fig. 5.4). Unfortunately, there is no clear vision as to where such huge pumped hydro system could be installed. Therefore, hydrogen storage technology with underground caverns is the most realistic option. Compressed air storage systems are not suited for this application due to high specific costs for the storage media.

The reference case "load levelling in transport grids" represents the class of large existing pumped hydropower stations, such as Vianden and Goldisthal. The results show that adiabatic compressed air storage systems are comparable from the cost point of view. However, the impact of compressed air storage systems on the

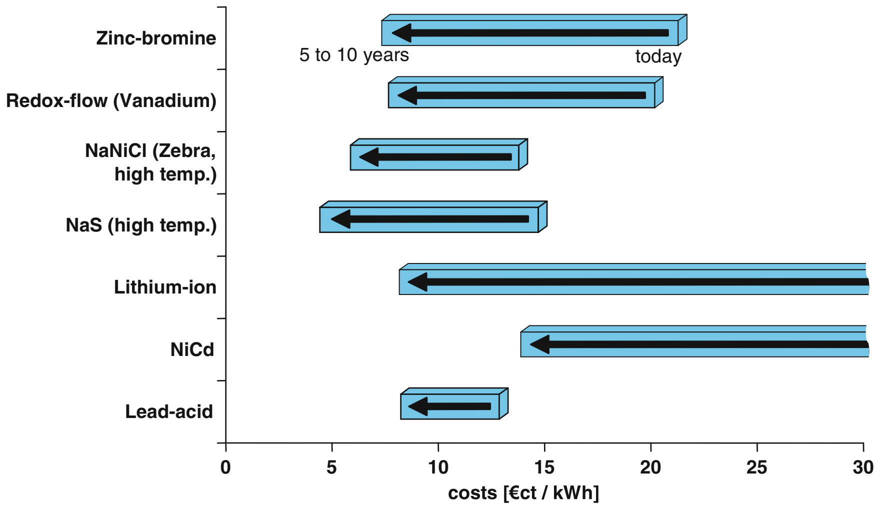

Fig. 5.6 Comparison of life cycle costs per delivered kWh for the reference case "peak shaving in the LV grid" (system lifetime 20 years, capital costs 8%, electricity costs 5 €ct/kWh)

environment is significantly less compared with new artificial lakes for the pumped hydro systems. Hydrogen storage systems are competitive for daily storage systems due to their low efficiency. However, this result depends very much on the assumed costs for the electricity that would need to be purchased to compensate the efficiency losses.

Calculations not shown here indicate that battery technologies have a medium to long-term potential of 8–12 €ct/kWh. Such battery systems must be designed in a highly modular way from several smaller units. However, the costs are approximately twice as high as for the pumped-hydro storage systems.

For the reference case "peak shaving in the LV grid", all the different battery technologies can generally serve the requirements. The results show that the NaS battery technology has the best potential in terms of costs, followed by the lead-acid batteries. Zinc-bromine and vanadium redox-flow batteries can come close, but they are several years behind in status with regard to technical developments and the available field experience. Because the specification asks for two cycles per day, the specific costs are at best in the range of 5 €ct/kWh.

To analyse the impact of the chosen parameters on the results, a sensitivity analysis has been performed. The results are shown here only qualitatively to get an idea of which parameters to keep an eye on (Table 5.15).

The analysis is focused on the storage system classes "modular storage for grid use only" and "centralised storage systems" which are at the same time also part of the "electricity to electricity" class. A generalised analysis of the "modular storage with double use" technologies is very difficult because the costs depend too much on their main application.

Table 5.15 Qualitative results from the sensitivity analysis for two different reference cases and technologies

Parameter	Reference case “load levelling in the transport grid”, technology “pumped hydro”	Reference case “peak shaving in the LV grid”, technology “lead-acid battery”
Efficiency	Low to medium	Low
Electricity costs	Medium to high	Medium
Costs per installed capacity	High	High
Number of cycles per day	High	High
Capital costs	Medium	Low
Self discharge	Not analysed	Very low
Maintenance and repair costs	Not analysed	Very low

In addition to the previously discussed issues, a cost analysis reveals some important general findings:

– Most storage technologies have high initial investment costs and low operational costs. Only those storage technologies with relatively short lifetimes or low efficiencies have significant costs during their lifetimes. Therefore, capital costs are very sensitive to life cycle costs. This is comparable in the case of power production from renewable energies, such as wind and PV generators.
– Battery technologies with a cycle lifetime but also high investment costs can hardly compete with battery technologies with shorter lifetimes and lower investment costs. As an example, doubling the lifetime of a storage technology from 10 to 20 years at a capital cost rate of 8% is only economical if the investment costs do not increase by more than 44%.
– Among the pure storage systems for the long-term storage task, only hydrogen storage systems and pumped-hydro systems have a chance. However, in Germany there is very little potential for pumped hydro technology. Hydrogen storage systems are attractive despite the low efficiency if underground salt caverns are used for storage.
– It is interesting to see that the cost projections for the coming years for most of the battery storage technologies are somewhere in the range of 5–10 €ct/kWh for a scenario of 2 cycles per day. This shows that it is worthwhile to follow the development of several different battery technologies and to see which of the technologies can ultimately meet the expectations.

5.7 Assessment of Future Viability of the Technologies’ Environmental Issues, Resource Use and System Characteristics

A major question related to auxiliary technologies for the generation and distribution of electrical energy, such as energy storage and electrical networks, is their viability in a future energy system. The main aim here is to consider whether

aspects that are relevant for a long-term viable usage of the energy system could hamper the application of auxiliary technologies in the future.

First, the methodology and data used for the quantitative assessment is explained. Then environmental impacts, resource use and system characteristics are analysed. A conclusion discusses the results of the analyses.

5.7.1 Methodology and Data Applied for Quantitative Assessment

The basis for evaluating technologies, particularly in relation to their environmental and resource suitability, is life cycle calculations. The technologies in focus are auxiliary energy storage technologies. It is beyond the scope of this study to carry out complete life cycle assessments of all auxiliary technologies, including energy storage systems and upgrades and extensions of electricity networks. Instead, published life cycle assessments are reviewed and analysed. In addition to journal articles and reports, data from the widely applied ecoinvent database (version 2.2, Ecoinvent 2010) are considered and used with the SimaPro life cycle assessment software. Based on this dataset, a life cycle screening of the technologies is made applying life cycle data on background processes and on the energy system for 2050 generated in the integrated project NEEDS[3] (European Commission 2008b; ESU and IFEU 2008) (see also Sect. 3.1.3). The background processes projected to 2050, which for the study were individually implemented into the ecoinvent database, include production processes for aluminium, copper, nickel, iron, steel, metallurgical grade (MG)-silicon, zinc, clinker and flat glass as well as the electricity mix of UCTE countries and aluminium production. Details are described in ESU and IFEU (2008). For the impact analysis made by this study, when no sound estimates are available relating to future technological developments, it is assumed that current technologies remain unchanged into the future. Where sound estimates for future developments are available, these are taken into consideration.

5.7.2 Environmental Impacts

5.7.2.1 Assessment Methodology and Assumptions

In order to evaluate the technology options with respect to their environmental impacts, an analysis of impacts and, where possible, related external costs is carried out. The estimated values of external costs can be considered in addition to the pure market-reflected costs for system optimisation purposes. Two types of technologies are investigated in the analysis: storage technologies and electrical networks. In order to make the results for the technologies comparable, the following functional units have been applied:

[3] "New Energy Externalities Development for Sustainability" – intergrated project funded by the European Commission in the sixth framework programme.

– For storage technologies: kWh electric energy provided over the entire lifetime,
– For distribution and transmission lines: an elementary unit of 1 m installed power line.

For the environmental impact assessment, two methodologies where followed. The first is the so-called impact pathway approach developed within the ExternE project series. Starting from emissions of substances, concentration increases are estimated. These are used in exposure-response functions derived from epidemiological studies to assess individual impacts, which finally are evaluated as far as possible to arrive at external cost values. The impact pathway assessment has the advantage that the effects can be attributed to sources. The evaluation of diverse effects can be very impact specific. For instance, human health effects are distinguished with respect to individual diseases, with the applied monetary values considering as far as possible the direct individual loss of utility due to pain, suffering and time lost (see, e.g., Hunt and Markandya 2001). These are ideally deduced from willingness-to-pay studies as well as the indirect economic effects of production losses and health expenditures. The diseases and monetary valuation for human health impacts used in the calculations are shown in Table 5.16.

As data from life cycle screening are used for the estimations and thus the relevant emissions are distributed over Europe, damage factors, which have been averaged over the geographical areas and height of emission from Preiss et al. (2008), were applied. The factors have been assessed on the basis of detailed runs of the EMEP model, "a multi-layer atmospheric dispersion model for simulating the long-range transport of air pollution" (Tarrasón 2009, p. 3) with a horizontal resolution of $50 \times 50\ km^2$ (see ibid.), and detailed data of the analysed receptors, assuming the current geographical distribution together with respective exposure response functions and specific monetary values (see Preiss et al. 2008). Thus, impacts on human health, crop losses, material damages of facades and loss of biodiversity are covered. Details on the effects covered in the remaining impact categories and on the explicit monetary values used can be found in (ibid.). In order to show the influence that variations of the most controversially discussed evaluation, i.e., the valuation of years of life lost due to chronic exposure by particles, may have, upper and lower bounds of 100,000 and 25,000 € per year of life lost, as recommended by Desaigues et al. (2006), are applied for the sensitivity analysis.

For the evaluation of climate change effects, the medium value of 70 €/$tCO_{2,equivalent}$,[4] recommended by the German Environment Agency in its methodological convention on external costs assessments, was applied (Umweltbundesamt 2007). The value represents a "best guess" on marginal damage costs derived from assessments carried out by Downing et al. (2005) with the so-called FUND model and has been recommended by Krewitt

[4] If not differently indicated, the base year 2000 is used for the evaluation of environmental effects.

Table 5.16 Human health effects and their evaluation as example for the approach applied in the study

	Risk group	Physical impact [1/(μg/m^3)]	Specific impact unit	Specific monetary value [€/impact unit]
Primary and secondary inorganic aerosols <2.5 μm				
Life expectancy reduction – chronic effects	All	6.51E-04	YOLL[a]	40,000
Net restricted activity days	All	9.59E-03	Days	130
Work loss days	All	1.39E-02	Days	295
Minor restricted activity days	All	3.69E-02	Days	38
Primary and secondary inorganic aerosols <10 μm				
Increased mortality risk (infants)	Infants	6.84E-08	Cases	3,000,000
New cases of chronic bronchitis	All	1.86E-05	Cases	200,000
Respiratory hospital admissions	All	7.03E-06	Cases	2,000
Cardiac hospital admissions	All	4.34E-06	Cases	2,000
Medication use/ bronchodilator use	Children	4.03E-04	Cases	1
Medication use/ bronchodilator use	Asthmatics	3.27E-03	Cases	1
Lower respiratory symptoms (adult)	Symptomatic adults	3.24E-02	Days	38
Lower respiratory symptoms (child)	All	2.08E-02	Days	38
Ozone [μg/m^3] (based on sum over means over 35 ppb)				
Increased mortality risk	All	2.23E-06	YOLL	60,000
Respiratory hospital admissions	All	1.98E-06	Cases	2,000
Minor restricted activity days	All	7.36E-03	Days	38
Medication use/ bronchodilator use	Asthmatics	2.62E-03	Cases	1
Lower resp. sympt. excluding cough	All	1.79E-03	Days	38
Cough days	All	1.04E-02	Days	38

Source: Preiss et al. (2008)
[a] YOLL: *y*ears *o*f *l*ife *l*ost

and Schlomann (2006). For sensitivity analysis, values of 20 and 280 €/tCO_2 have been recommended (Umweltbundesamt 2007). The substances considered for the analysis comprise the classical air pollutants SO_2, NH_3, NMVOC, NO_X

and primary particles, as well as greenhouse gases, toxic substances and radionuclides.

As a second approach, in order to cover further impacts, a widely applied standard method of Life Cycle Impact Assessment "CML 2001" is used. The effects are analysed in detail so that individual aspects of relevant technologies can be discussed. Using this methodology, a large variety of impact categories can be covered: abiotic depletion, acidification, eutrophication, global warming, ozone layer depletion, human toxicity, fresh water aquatic ecotoxicity, marine aquatic toxicity, terrestrial ecotoxicity and photochemical oxidation. In each category a substance is selected which is used as a reference. The potential effects of other substances are then estimated relative to this reference substance. On this basis, factors are derived which make it possible to express the potential effects of all substances in each category in terms of equivalents of the reference substance. Thus, the potential impacts of all substances can be aggregated by category, assuming implicitly average conditions. According to the baseline assumptions in the CML 2001 method, the following time horizons are used: 100 years for the global warming potential (GWP100) and infinite time horizon for the toxicity effects. For ozone layer depletion, steady state has been assumed. The results for the individual impact categories are not further aggregated.

5.7.2.2 Environmental External Costs of Balancing Technologies

Figure 5.7 shows the external costs, assessed by following the impact pathway approach for storage technologies and alternative technologies with the data from ecoinvent 2.2 extended by data assumed for the future energy system within the NEEDS project (Ecoinvent 2010; NEEDS 2010). Assumptions for the cycle life of the batteries used were 3,000 for NiMH and 4,500 for Li-Ion batteries and for the gravimetric energy density 80 and 200 Wh/kg, respectively. Assuming the results of life cycle assessment from Rydh (1999), the numbers for lead-acid batteries include the processes of production of secondary (99%) and primary lead (1%) (26.8 g lead/kWh_{el}) and sulphuric acid (4.2 g sulphuric acid/kWh_{el}). As no complete data for hydrogen storage is available, data from the assessment of hydrogen electrolysis for a hydrogen fuel station are taken from NEEDS (Maack 2008). The values assessed represent costs occurring due to emissions in 2050.[5]

From the results, it becomes obvious that emissions of SO_2 will prospectively lead to the largest effects caused by using energy storage units. These are, for example, in the case of the NiMH battery[6] and the electrolyser generated by high direct SO_2 emissions in the nickel production process. As lead-acid and lithium-ion batteries are much more relevant for energy balancing and the results for NiMH are so high, the bar has only been displayed up to 10 € per MW_{el} provided. Although

[5] In order to project costs from today to 2050, the growth rate of GDP is assumed to be 2% until 2030 and 1% thereafter, with an income elasticity of 0.85.

[6] As no other data are available, for the NiMH battery a dataset for 1 kg of notebook batteries is taken from ecoinvent 2.2.

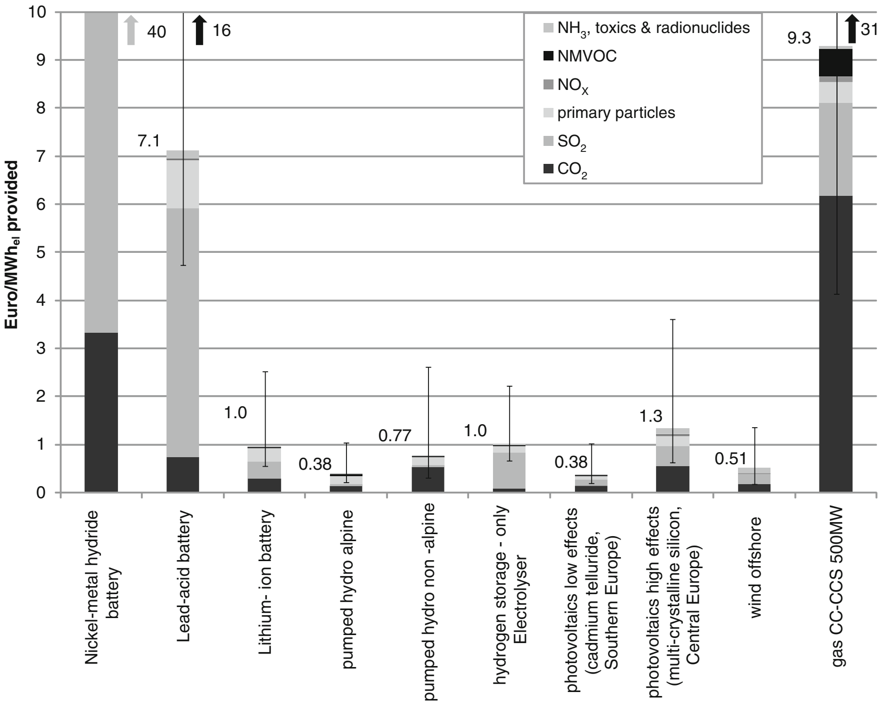

Fig. 5.7 External costs in 2050 of analysed storage technologies, considering only their construction, and a photovoltaic facility, a wind power plant, and a gas combined cycle plant with CCS, considering the whole life cycle, in € per MWh provided. (The values for the storage facilities do not include the operation phase so that the electricity loss due to storage is not considered in the estimates. However, this can easily be calculated from the values by assuming a certain technology for electricity production. Using electricity from wind offshore plants assessed here and an efficiency of the storage option of 80% would result for example in additional external costs of $0.51 * 0.2 \approx 0.1$ € per MWh_{el}. For the assessment of nickel-metal hydride batteries, the ecoinvent unit process for batteries in notebooks is taken. For lead-acid batteries, only the processes of providing lead and sulphuric acid are considered according to the material required per kWh_{el} taken from Rydh (1999, p. 23). The other processes are directly taken from NEEDS life cycle results (photovoltaics, wind, gas power plant) and respective ecoinvent unit processes (all others))

the electricity system includes a high share of renewable energies, some CO_2 emissions still remain in the life cycle, particularly due to material production processes. The high values of the NiMH and lead acid batteries could be reduced by increasing the cycle lifetime significantly. The results for the lithium-ion battery, pumped hydro and the electrolyser are about equally high with the option of applying pumped hydro in alpine regions showing lower life cycle effects than in non-alpine regions. Furthermore, results for photovoltaic systems, representing a

situation with low effects and one with high effects, and for a wind offshore plant, based on results from the NEEDS life cycle database (NEEDS 2010), are shown. These concur over a potential over-installation of plants. However, it has to be born in mind that the effects per produced energy unit will clearly increase with a decrease in usage, and thus in the total electricity produced by the plant, which has to be considered in case of over-installation. In total, the external costs estimated for the natural gas combined cycle plant, also represented here, with post-combustion carbon capture and storage (CCS) technology projected to 2050 (NEEDS 2010) are high, but lower than for NiMH batteries and at about the same level as lead-acid batteries per kWh electricity produced or stored and delivered respectively. Climate change effects still dominate the results for the gas power plant, although carbon is captured and stored.

Assuming the value of 280 €/tCO_2 for the evaluation, particularly the external costs of the gas combined cycle (CC) plant with CCS would increase by a factor of three. The ranking between the storage technologies changes only slightly. In contrast, assuming the value indicating the lower bound of 20 €/tCO_2, the total external costs assessed for the gas CC plant with CCS would reduce by about a factor of two. In that case, the ranking remains mainly unchanged. The error bars drawn in the diagram represent the maximum range by assuming the discussed values on marginal climate changes damage costs and on life years lost. However, although these represent major uncertainties in the analysis, further uncertainties exist which are not considered in the error bars. Nonetheless, the results can be used to get an impression of the strengths and weaknesses of the different technologies in terms of environmental impacts, and show in which order of magnitude the resulting external costs are.

Beyond the use of storage systems, changes in energy supply systems make it necessary to expand the electricity grids to function on different voltage levels (see Sect. 6.1). Depending on the balancing strategies, the voltage needs can be higher or lower. Such an expansion has to be considered particularly if the chosen strategy is an over-installation of photovoltaic and wind power plants, because it increases the power of remote solar and wind plants and, thus, the required network capacity. This is not necessarily the case for storage options. Accordingly, in addition to the external costs of storage systems, the grid connections are analysed with respect to external costs. Figure 5.7 shows the estimated external costs associated with the construction of transmission and distribution lines. The lines represent average technologies of today's networks as defined within ecoinvent 2.2 (Ecoinvent 2010). The external costs are calculated as if the technologies are still in use in 2050. The estimated effects for high-voltage grids are dominated by the results for climate change. The reason is the high levels of CO_2 emissions in the steel and aluminium production processes. The error bars indicate the maximal variations by applying the values for climate change effects and years of life lost from the sensitivity analysis, as discussed above (Fig. 5.8).

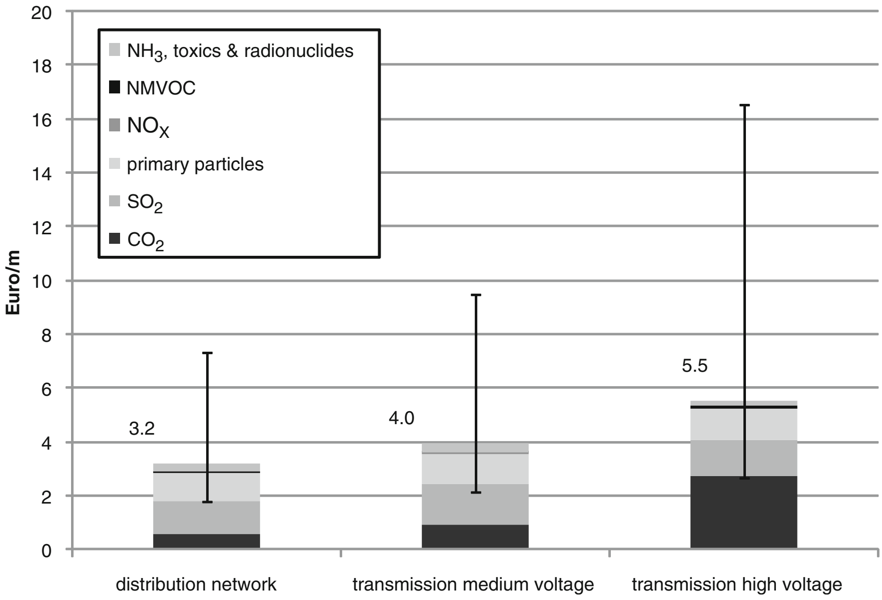

Fig. 5.8 External costs in 2050 of analysed transmission and distribution lines in € per metre (m) line constructed, calculated for a lifetime of 30 years (Data were taken from ecoinvent 2.2. Data for steel production were adjusted to German conditions, assuming 500 m for the distance between masts)

5.7.2.3 Environmental Impacts of Balancing Technologies Differentiated into Categories

Figure 5.9 shows the results for the assessment of impact categories following the assumptions used in the CML 2001 evaluation framework. In addition to relevant storage technologies,[7] photovoltaic and wind power plants as well as further gas power plants as projected in NEEDS (2010) are considered: a gas combined cycle (CC) plant with post combustion carbon capture and storage (CCS) technology (500 MW) as considered in the external costs analysis, a gas turbine (50 MW) and the gas combined cycle plant without CCS technology (500 MW). The presentation of individual impacts allows the development of a more differentiated picture of environmental effects.

In contrast to the assessed external costs which typically include only small marginal effects, not covering critical environmental damages (see Sect. 2.2.1), the evaluation in impact categories shows potential outcomes which also include critical effects with potentially unacceptable impacts such as eutrophication, acidification, land use, depletion of the ozone layer and the greenhouse effect.

[7] The NiMH battery technology has been left out here because it is not as relevant as the options of lead-acid and lithium-ion batteries and would dominate the results.

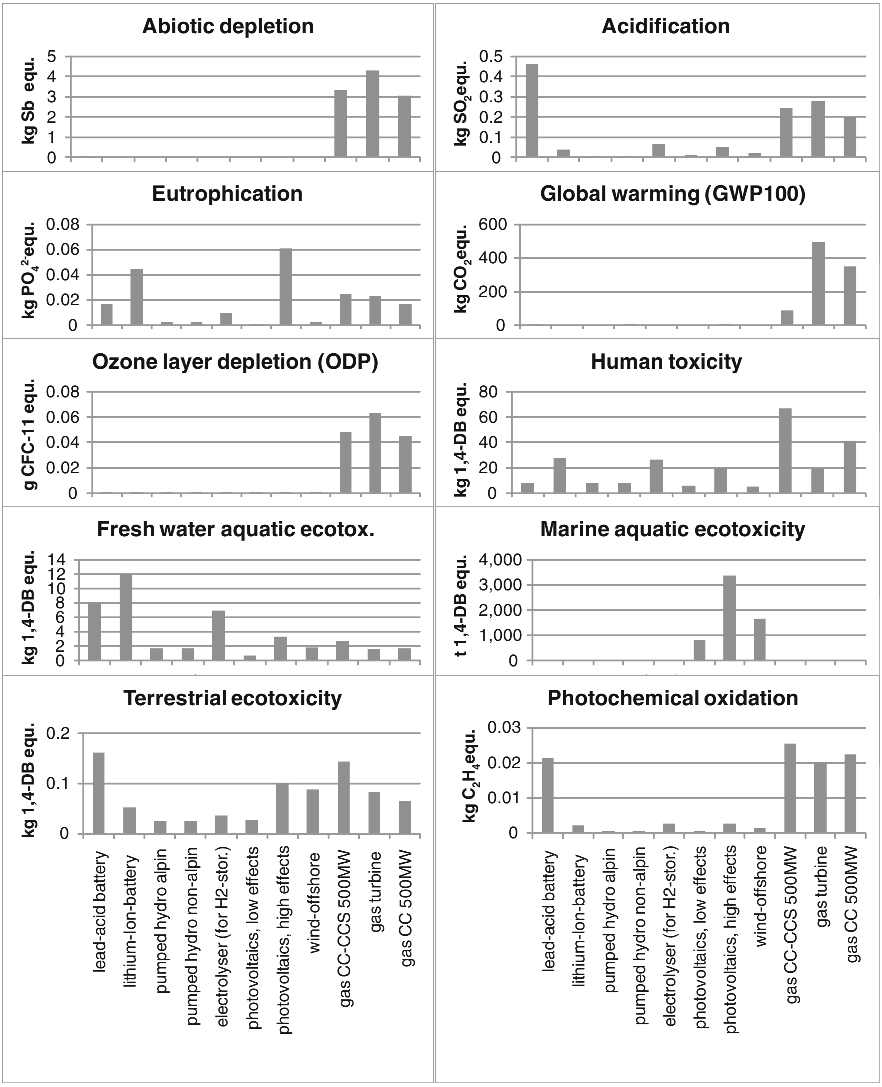

Fig. 5.9 Environmental impacts per MWh_{el} by existing storage technologies, photovoltaic and wind power, and three options for using natural gas. The assumption is based on projections for 2050 conditions, which is the scenario "very optimistic" of the NEEDS project and which assumes 80% electricity production from renewable resources (see Sect. 3.1.3)

The pumped hydro plants and the electrolyser show the best performance in all categories. The lithium-ion battery performs worse than these technologies, but at a level similar to the electrolyser and better than other options, except for in the categories eutrophication and fresh water aquatic ecotoxicity. The lead-acid battery shows high effects, particularly in the area of acidification, fresh water aquatic

ecotoxicity, terrestrial ecotoxicity and photochemical oxidation. The natural gas power plants dominate the categories of abiotic depletion, ozone layer depletion and global warming. Building more wind and photovoltaic power plants in particular would have an effect on marine aquatic and terrestrial ecotoxicity.

5.7.3 Resource Use

5.7.3.1 Types and Amounts of Resources Required

Many mineral resources are used for energy storage and transmission and distribution lines. As we have already seen above, in the results relating to the environmental impacts associated with the production of energy storage technologies, energy storage, transmission and distribution lines, these are the main sources of SO_2 and CO_2 emissions when the electricity mix is dominated by renewable energies.

Table 5.17 gives an overview of the amount of minerals used in batteries per kWh electricity produced during the lifetime of the battery. The information in the table allows a prediction of the extent to which various mineral materials would be required in a future energy system using the listed battery technologies at current development status. As lithium-based, lead-acid and vanadium redox-flow batteries

Table 5.17 Minerals used for different battery types in percentage of weight considering the whole life cycle following Rydh and Svärd (2003, p. 172) and Rydh (1999, p. 23)

Substance	NiCd	NiMH (AB5)	NiMH (AB2)	Li-based	Lead-acid	Vanadium redox-flow
Aluminium	0.019	0.5–2.0	0.5–1.0	4.6–24		
Cadmium	15–20					
Cerium		0.43–5.5				
Cobalt	0.60	2.5–4.3	1.0–3.0	12–20		
Chromium	0.017	0.02–0.08	0–1.6			
Copper				5.0–10	0.3	0.8
Iron	29–40	20–25	23–25	4.7–25		
Lanthanum		1.4–6.6				
Lead					61	
Lithium				1.5–5.5		
Manganese	0.083	0.81–3.0		10–15		
Neodymium		0.96–4.1				
Nickel	15–20	25–46	34–39	12–15		
Praseodymium		0.32–1.3				
Titanium			2.2–3.9			
Vanadium			2.2–4.7	15–20		5.6
Zinc	0.060	0.092–1.6				
Zirconium			3.9–8.7			
Antimony, tin, arsenic					2.1	

represent the most important options for stationary applications (see Sect. 5.2.3), the most important metals for this study are aluminium, antimony, arsenic, cobalt, copper, iron, lead, lithium, manganese, nickel, tin and vanadium.

It is important to remember that many of these materials will also be required for electrolysers, gas turbines, fuel cells and other uses. Thus, the list of materials of interest is longer than that mentioned above. In the following, the situation of an extended list of materials will be discussed with respect to the reserves-to-production ratio and supply-side concentrations. These figures are generated based on general data for resource availability and production.

5.7.3.2 Current Availability of Relevant Mineral Resources

Table 5.18 focuses on relevant mineral resource data. High prices show there is a scarcity of a mineral. The highest prices currently being paid, especially for platinum group metals, are in the range of millions of US dollars per tonne. Even if only small amounts of these metals are needed, it could lead to high production costs. The largest increases of prices between 2001 and 2006 were observed for cadmium (470%), nickel (460%) and zinc (450%), followed by copper (350%) and cobalt (250%). Also high increases (>100%) were observed for bauxite, chromium, iron, manganese, platinum, and zircon oxide. The reason for the price increases is the growing demand from the so-called BRIC countries – Brazil, Russia, India and China. These countries have had very high growth rates over the last many years.

As an indicator of the sustainable use of resources, the reserves-to-production ratio can be used. Following Steger et al. (2005) (see also Sect. 2.2.2), reserves must not fall below 60 years to prevent system breakdowns. Looming reserve shortages are visible in the cases of antimony, arsenic, cadmium, chromium, copper, lead, manganese, nickel, tin, zinc and zircon oxide. In the case that one of these materials should run low, system change would have to be accelerated to prevent shortages in the availability of important technologies and spikes in prices during the transition phase to a new energy system. A further indicator of resource sustainability is the decrease of the reserve-to-production ratio. Only supplies of arsenic, copper, lithium, nickel, titanium, and zircon oxide appear to be stable. All other analysed mineral resources show a decrease in the reserve-to-production ratio, which means, following Steger et al. (2005), that these are not being used in sustainable ways. Even more alarming is that the reserve base is already below the 60-year mark for a large number of the minerals considered here. Figure 5.10 shows minerals with strongly varying reserve-to-production ratios with values below 100 years. While the reserves-to-production ratio for titanium increased permanently to values above 100 years and the value for cobalt is only occasionally crossing the 100-year line, the values for iron, yttrium and manganese decreased over the past years. They appear to have stabilised at around 70, 60 and between 40 and 60 years, respectively. Tin is continuously decreasing and is now at the low level of below 20 years availability.

Regional concentrations of reserves and the delivery and revenue chain are also relevant. There are various cases where there are very large reserves (70 or more percent of known reserves) concentrated in just two countries (see Table 5.19). This

Table 5.18 Prices, price increases, reserves-to-production and reserve-base-to-production ratios

Substance	Price (average in 2006) [US$/t]	Price increase (end of 2001 to end of 2006) [%]	Reserve-to-production ratio in 2009 [years][a]	Increase of reserves-to-production ratio (1996–2009) [%]	Reserve-base-to-production ratio in 2008 [years][b]
Antimony	–	–	11	−30	22
Arsenic	–	–	20	0	30
Bauxite	2,700	110	134	−33	185
Cadmium	3,400	470	31	−10	61
Chromium	1,400	130	15	–	41
Cobalt	35,000	250	106	−28	171
Copper	6,700	350	36	21	65
Iron	72	170	70	−54	158
Lead	1,300	250	20	−14	44
Lithium	210	−15	550[c]	203	433
Manganese	280	130	56	−36	391
Nickel	25,000	460	50	14	96
Platinum group metals			190	−13	204
Platinum	37,000,000	140			
Palladium	10,000,000	−18	–	–	–
Ruthenium	6,200,000	−24	–	–	–
Tin	9,000	83	18	−49	37
Titanium			127	70	233
Ilmenite	80	−20	131	76	241
Rutile	475	0	85	−27	147
Vanadium	–	–	241	−16	685
Yttrium	10,000 −89,000	–	61[d]	−81[d]	69
Zinc	3,300	450	18	−4	41
Zircon oxide	750	144	46	22	60

Sources: BGR (2007), USGS (2010)

[a] Reserves represent that part of the resources/reserve base that could be economically extracted or produced at the time of determination (see definitions at USGS 2010)

[b] The reserve base is the in-place demonstrated (measured plus indicated) resource from which reserves are estimated (see definitions at USGS 2010)

[c] Extreme increase from 2008 to 2009, particularly because of high increase in reserves in all countries and estimated decrease in production for 2009 (see USGS 2010). Other sources mention higher numbers, for example, Roskill (2009) with 24 million tons in comparison to 9.9 million tons listed at USGS (2010) (see also Angerer et al. 2009)

[d] Value in 2008

is the case for chromium (88%), cobalt (74%), lithium (84%), platinum group metals (97%), vanadium (76%) and zirconium oxide (70%). The situation is similar for the concentration in the supply chain, as can be seen in the cases of the platinum group metals, yttrium and zircon oxide. High concentration among corporate

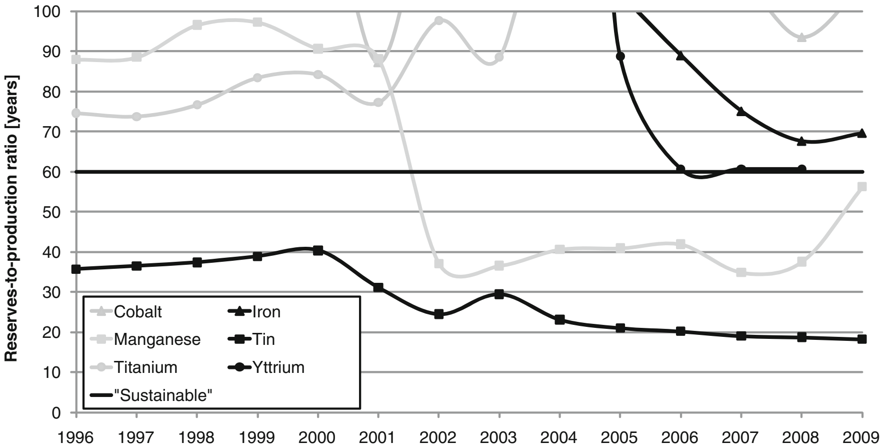

Fig. 5.10 Mineral resources showing varying or significantly decreasing reserve-to-production ratios at low levels from 1996 to 2009

providers is observed in the case of palladium where the Russian firm, Norilsk Nickel, covers 50% of the delivery and revenue chain.

It is difficult to accurately evaluate countries with respect to their contractual and political behaviour. Nonetheless, there are many problems with the metal markets associated with Russia, China, Ukraine, Pakistan and India (Behrendt et al. 2007). China and Russia, respectively, determine market availability and potentially the prices of yttrium and palladium.

For some minerals, such as titanium, the resource supply is unproblematic. There are also only relatively few problems associated with lithium and vanadium for which large reserves and reserve bases exist. Copper, nickel and zircon oxide, with an increase in reserve-to-production ratio/period of secured practice showing an estimated value of about 36–50 years, are being used more or less sustainably. In the case of some of these minerals, especially lithium, vanadium and zircon oxide, however, there are large regional concentrations in the supply chain in only a few countries.

5.7.3.3 Resource Potentials for the Production of Balancing Technologies

Of all balancing technologies, particularly batteries have high mineral resource requirements. The most important battery types for this analysis are lithium-ion, lead-acid batteries and redox-flow batteries making use of vanadium. In order to get an impression of the material requirements relative to the minerals available, and following the concept of Rydh (1999, p. 26), Table 5.20 shows the theoretical energy capacity that could be realised with the reserves. Numbers in brackets indicate the case that the reserve-to-production rates are kept at 60 years, which is assumed to be a sustainable rate. Assumptions for the gravimetric energy density

Table 5.19 Regional and corporate concentration of reserves and characteristics of delivery and revenue chain for relevant mineral resources (see BGR 2007; USGS 2010)

Substance	Regional concentration in reserves (2009)[a]	Regional concentration in delivery/revenues chain (2005)	Corporate concentration in delivery and revenues chain (2005)[b]
Antimony	China (37%), Thailand (20%)	–	–
Arsenic	–	–	–
Bauxite	Guinea (27%), Australia (23%)	Australia (34%), Brazil (13%)	Alcoa (USA, 16%), Alumina Ltd. (Australia, 9%)
Cadmium	China (15%), Russia (12%)	China (16%), South Korea (13%)	Industias Penoles (Mexico, 5%), Zinifex (Australia, 3%)
Chromium	Kazakhstan (51%), South Africa (37%)	South Africa (43%), India (19%)	Eurasian Nat. res. Corp. (KZ, 19%), Kermas Group (GB, 18%)
Cobalt	Congo (51%), Australia (23%)	Congo (40%), Canada (10%)	Inco (Canada, 8%), Glencore (Switzerland, 4%)
Copper	Chile (30%), Peru (12%)	Chile (40%), USA (8%)	Codelco (Chile, 13%), BHP Billiton (Australia, 9%)
Iron[c]	Russia (18%), Australia (17%)	Brazil (22%), Australia (20%)	CVRD (Brazil, 19%), Rio Tinto (GB, 9%)
Lead	Australia (29%), China (15%)	China (31%), Australia (23%)	BHP Billiton (Australia, 9%), Doe Run (USA, 8%)
Lithium	Chile (76%), Argentina (8%)[d]	Chile (45%), Australia (24%)	GEA Group AG (GER, 24%), Sons of Gwalia (Australia, 24%)
Manganese	Ukraine (26%), South Africa (24%)	China (18%), South Africa (16%)	Samacor (South Africa, 19%), CVRD (Brazil, 9%)
Nickel	Australia (37%), New Caledonia (10%)	Russia (21%), Canada (14%)	Norilsk Nickel (RU, 18%), Inco (Canada, 14%)
Platinum group metals	South Africa (88%), Russia (9%)	–	–
Platinum	–	South Africa (78%), Russia (13%)	Anglo American (GB, 34%), ImpalaPlatinum Hld. (SAF, 21%)
Palladium	–	Russia (44%), South Africa (40%)	Norilsk Nickel (RU, 50%), Anglo American (GB, 18%)
Ruthenium	–	–	–
Tin	China (31%), Indonesia (14%)	China (40%), Indonesia (27%)	State of Indonesia (17%), Minsur (Peru, 15%)
Titanium	–	Australia (31%), South Africa (20%)	Rio Tinto (GB, 24%), Iluka Resources (Australia, 20%)
Ilmenite	China (29%), Australia (19%)	–	–
Rutile	Australia (48%), South Africa (18%)	–	–

(continued)

Table 5.19 (continued)

Substance	Regional concentration in reserves (2009)[a]	Regional concentration in delivery/revenues chain (2005)	Corporate concentration in delivery and revenues chain (2005)[b]
Vanadium	China (38%), Russia (38%)	–	–
Yttrium	China (40%), USA (22%)	China (99%)	–
Zinc	China (17%), Australia (11%)	China (25%), Australia (14%)	Teck Cominco (Canada, 7%), Zinifex (Australia, 6%)
Zircon oxide	Australia (45%), South Africa (25%)	Australia (39%), South Africa (33%)	Iluka Resources (AUS, 35%), Anglo American (GB, 18%)

[a] For Yttrium: 2008
[b] *KZ*: Kazakhstan, *GB*: Great Britain, *GER*: Germany, *SAF*: South Africa, *RU*: Russia, *AUS*: Australia
[c] Iron content
[d] Some sources estimate more reserves in Argentina (e.g., Tahil 2007; Angerer et al. 2009)

Table 5.20 Theoretical battery capacity realisable with current reserves following an indicator defined by Rydh (1999, p. 26)

Substance	Li-based	Lead-acid	Vanadium redox-flow
Cobalt	6.6–11 (2.9–4.8)		
Copper	1,100–2,200 (ns)	6,840 (ns)	1,700 (ns)
Iron	130,000–680,000 (18,000–94,000)		
Lead		4.9 (ns)	
Lithium	36–130 (32–120)		
Manganese	720–1,100 (ns)		
Nickel	95–120 (ns)		
Vanadium	13[a]–17 (9.8–13)		5.8 (4.4)

Numbers in brackets show the case that the reserves are used sustainably so that the reserve-to-production ratio is 60 years as minimum ("ns" means no sustainable use possible, because the reserve-to production ratio is already below 60 years). The numbers are expressed in TWh electricity storable
[a] Lithium-polymer batteries on a vanadium basis, assuming the same gravimetric density as lithium-ion batteries

were 200, 38 and 25 Wh/kg for lithium-ion, lead-acid and redox-flow batteries, respectively.

With respect to the known reserves, very high battery capacities of at least some TWh could theoretically be realised with each technology. At a minimum, the estimated amounts are 6.6 TWh_{el} for lithium-ion batteries, 4.9 TWh_{el} for lead-acid batteries and 5.8 TWh_{el} for vanadium redox-flow batteries. The lithium battery production could be increased if no vanadium or manganese were required, as these are the limiting minerals. Compared to the derived storage capacity required in 2040+ of 1.7 TWh_{el} in the case of Germany (see Sect. 4.1.1.3), these numbers are higher but in the same order of magnitude. This suggests that these technologies cannot be the only solution for balancing electrical energy and power in the system.

In the case that lithium-ion batteries are used in electric vehicles and assuming that these require a capacity of 10 kWh_{el} and have a range of about 100 km, then, if the 6.6 TWh_{el} estimation for cobalt is accurate and binding,[8] 660 million cars could be built. This means about one car per ten people. This is about the number of passenger cars in the world today (see, e.g., Angerer et al. 2009: 800 million vehicles in 2008; Wikipedia 2011: 600 million passenger cars in 2007, strongly increasing). If it is assumed that the reserves of lithium will be binding instead of cobalt, because no or limited cobalt is required for the specific Li-ion battery type, the realisable capacity increases to 36 TWh_{el} and the number of electric vehicles that could be realised under the above assumptions increases to 3.6 billion.

The numbers become smaller (see Table 5.20, numbers in brackets) if it is assumed that the reserve-to-production ratio has to be 60 years or higher in order to allow enough time for switching the system, and reserves are continuously decreasing. In this case, these technologies would seem to be no longer applicable in the long run as they do not meet the sustainable resource use criterion set forth in Steger et al. (2005) (see also the discussion of "period of secure practice" as an indicator for sustainable resource use in Sect. 2.2.2). For copper, lead, manganese and nickel, the reserve-to-production rates are already below 60 years although they show different trends (see Table 5.1). The capacity which could theoretically be realised if the reserve-to-production ratio of other minerals, such as cobalt, lithium and vanadium, is held to be at least 60 years, is only a little less than when using the whole reserves (see Table 5.20).

The numbers become higher if resources are assumed instead of the reserves. For example, for cobalt the "hypothetical and speculative resources" (USGS 2010) are estimated to be a factor of 150 times higher than the reserves. For vanadium, the resources represent more than about five times the reserves, for lead they are about 20 times higher, and for lithium a factor of 2.5–3 times higher (Angerer et al. 2009; Aul and Rittmeyer 2011; USGS 2010).

Beside the problem of absolute scarcity, relative scarcity, which could occur due to resource politics, has to be considered. Section 5.7.3.2 shows that reserves of cobalt and lithium are concentrated in only a few countries.

The rough calculations in this section show that high recycling rates of minerals will be necessary if the battery technologies are to be intensively used over long time periods. Additionally, alternative options for batteries confronted by only limited or no restrictions in the availability of minerals should be further analysed.

5.7.4 System Characteristics Relevant for Society

Aside from environmental effects and resource use, following the discussed indicators in Sect. 2.2, further relevant aspects are system characteristics of

[8] This depends on the amount of cobalt required for the specific type of Li-ion battery.

technologies, which can be subdivided into supply reliability, risk avoidance and openness of options. A more detailed look at these categories reveals that they are not distinct to environmental and resource aspects but include these partly, for instance risks from environmental pollution are included in the category “risk avoidance”. Therefore, the results from the previous two sections will be discussed here in the context of further important societal aspects. Furthermore, results from other analyses in the study are picked up to discuss the performance of the analysed technologies with respect to the indicators. Although the basis for the indicators here can be, and partly are, quantitative assessments, the indicators are discussed qualitatively.

5.7.4.1 Supply Reliability

Following the indicators derived in Sect. 2.2.3, the first aspect of system characteristics is supply reliability. However, several facets have to be distinguished.

The first facet is breakdown and quality of supply. The central task of storage systems and all balancing strategies is that the temporal availability of electricity and quality of supply increases with their application. In order to assure this, the diverse technologies applied have to fit to the specific tasks. Potentials and differences in technologies in this respect can be found in Sects. 5.1–5.5 and particularly in Tables 5.1, 5.2 and 5.3, where storage and supply systems are discussed with respect to their typical energy and power characteristics. The energy characteristic indicates how much energy ideally is gathered and provided by the system, comprising energy density and amount as well as relevant storage losses. The power characteristic focuses on how much energy can be provided per time unit, i.e., how fast energy can be gathered or provided. The ratio of energy to power gives the typical time scale on which the system can be employed. This discussion shows that the applicability of the individual technologies is highly dependent on the energy system’s needs. Therefore, in Sect. 4.2, in the pan-European modelling, two typical storage technologies are assumed: a long-term storage and a short-term storage.

Furthermore, the system of storage or supply itself has to be reliable. This requires that sufficient redundancy is implemented in the case of failure. This aspect becomes all the more important the larger the system is in total. In modular systems, such as a bundle of single batteries, individual elements can be shut down and repaired when they fail operationally, as they represent only a minor part of an entire system. This is different with central, non-modular systems, which use, for example, large gas turbine units. Occasionally these have to be taken from the grid completely. Thus, in order to assure redundancy they require large backup units in the system.

The second facet of reliability of supply is diversity. The diversity of technologies that can be used for the energy supply and distribution is definitely increasing with storage systems, although they support the restructuring of the total system from fossil to renewable energies.

The degree of diversity in an energy system is strongly related to import dependence. The more diverse the system is, the less susceptible it is to resource shortages and respective increases in price. The most important resources in the

energy area are the fuels required to run the power plants. However, the alternative technologies for balancing energy and power, such as storage systems, are aimed at reducing the use of those fossil energy sources. In this respect, therefore, all alternative storage technologies have to be evaluated positively. However, energy import dependencies will still remain with large central systems that efficiently make use of optimal energy fluxes or topological characteristics in different regions of Europe. This can be realised for example, by an over-installation of wind power in coastal regions, centralised solar power plants with thermal storage capabilities in southern Europe or large hydropower plants in the fjords of northern Europe. In such cases either electricity lines or other chemical fuels such as gases (e.g., biogas and hydrogen) will have to be transferred from the conversion plant to the consumer.

Another aspect concerns mineral resources required for the production of facilities. In the analysis of resource availability, it was shown that some resources could become critical so that the prices may increase due to relative or absolute scarcity. Thus, the price of resources could strongly increase in absolute terms or, for example, due to resource politics in the country of origin, be available only for domestic production, so that producers in Europe could have problems staying competitive. This could be a particularly serious problem with respect to producers in countries that have free access to resources.

Technological diversity has the advantage that alternative technologies can be used when technologies that were seen as especially hopeful prove less promising than expected. In designing economic and legal framework conditions, all promising alternatives should be given a chance. Alternatives that turn out to perform badly should be forced from the system.

A further aspect of supply reliability is fair and affordable access. With the possibilities for individuals to adjust their own demand to the supply through participating in demand-side management programmes, everybody can participate individually. System advantages generated by these contributions will prospectively be refunded to the participants via lower payments compared to the regular tariff. In addition to adjusting demand, individuals can in principle operate their own storage systems. Usable storage potentials already exist for some private homes in the form of combined heat and power plants. Stored heat can be used in such systems to temporally postpone electricity production from heat usage. Further interesting opportunities to contribute to the shortage of storage potential in the system could include batteries in cars, especially electric vehicles, as well as stationary batteries for storing electricity from decentralised photovoltaic. As long as the difference between the price paid by the consumer for electricity to the energy supplier and the extra costs paid for the storage system broken down to the energy produced is positive, using such systems to satisfy personal electricity demand can be competitive. With stationary batteries, this consideration is particularly relevant if a photovoltaic system is already installed and subsidies have been phased out. The extra batteries can, through a kind of double use, additionally be applied for stabilising the electricity system. Potential support for storage operations is discussed in Chap. 7. Regulations that may

hamper the use of storage systems for the stabilisation of the electricity supply are discussed in Chap. 8.

Also relevant in terms of supply reliability are options for participation. Particularly in the area of decentralised storage systems, participation in and co-determination of the electricity supply system will prospectively be possible without major effort. As already discussed above, a basic option is to participate via demand-side management, for example, by applying smart meters at home. In addition to adjusting demand, the systems with potential double use, such as batteries in electric vehicles and for photovoltaic plants, could represent the best opportunities for citizens to contribute to balancing the electricity system. This depends, however, on the contractual situation with the energy supplier, especially with respect to electric cars. Contractual constructions can be designed which could consider benefits receivable by contributing to balancing out electricity supply and demand.

5.7.4.2 Risk Avoidance

In the area of risk avoidance, a distinction between technical and environmental risks needs to be made.

With respect to technical risks, it is obvious from the descriptions of the technologies that the field of options usable for storing energy in order to support the electricity supply is very wide and heterogeneous. Therefore, a general statement covering all kinds of technological risks cannot be made. Many technologies that are currently available are in an early stage of development. Systems in which energy is stored require protective arrangements to ensure that the energy cannot be released suddenly and in an uncontrolled fashion. In order to be able to obtain public confidence and acceptance, it is essential that high priority is given to designing storage facilities in such a way that technical risks with a high potential for damage are practically eliminated. Furthermore, existing technical risks, including in the production chain, are to be minimised.

As can be seen from the analysis of environmental impacts, the most important environmental risks related to storage technologies are characterised as those where damage potentials are low, but many people are concerned. These have been discussed to a large extent in the section about environmental effects of technologies. However, special ecosystem risks can be observed, relating to acidification and eutrophication. Problems for the global environment can also be associated with ecotoxicity. With respect to the major aim of this study – finding means for implementing technologies for balancing electricity supply and demand – the analysed technologies perform well in comparison with options of using natural gas in turbines and combined combustion plants, even if carbon is captured and stored.

5.7.4.3 Openness to Options

Implementing balancing strategies increases the options for a future electricity supply. In order to ensure maximum openness for options, the system transformation has to be structured in such a way that the development and implementation of

promising existing and new technologies are not hampered. Thus, research funding should be oriented at the system services provided and not at specific technologies.

5.7.5 Conclusions on the Future Viability of Various Approaches to Energy Storage

The results of the analysis show that through a high penetration of renewable energies in the electricity sector and positive developments in electricity production processes, the construction of storage facility installations gains in importance in relation to improving air pollution levels, climate change mitigation and resource shortages. With the introduction of an electricity system run largely on renewable electricity, the problem of the high greenhouse gas emissions of the current system would be largely solved. With system change, however, it is important to realise that the protection of critical ecosystems could gain in importance. Beyond improvements in production processes, particularly related to the provision of minerals, the recycling of minerals will be important to prevent problems associated with the development of the analysed auxiliary technologies and other highly developed technologies. The reader should be aware that the analysis is only a rough screening of some currently available technologies in relation to a projected future production system. Thus, resource use questions and environmental impacts related to the new energy technologies need to be analysed in more detail on the basis of the life cycle data in further studies. Calculations need to be extended in order to cover more options for technological storage and network extension options. Table 5.21 shows the summary of results from the analysis.

5.8 Summary and Conclusions

A large variety of technologies can be applied for balancing energy and power in the electricity system. It could be shown that a characterisation considering the following aspects can provide an overview of different options:

– Type and location of the storage systems,
– The duration and frequency of supply and
– Input and output type of energy.

Given that the stages of technological development vary, further technological development may significantly change the appraisal of which technologies appear promising for fulfilling different tasks. Based on current cost levels and anticipated cost reductions in the next years, the following can be concluded:

– For long-term storage, hydrogen could benefit from low volume related costs (about 10 €ct/kWh achievable) compared to compressed air energy storages (CAES) (about 23 €ct/kWh achievable), whereas pumped hydro is much less expensive per kWh stored (less than 5 €ct/kWh achievable), but the technical potentials of appropriate sites is limited in Germany. The potential for hydrogen storage is high. Using today's natural gas storage systems for hydrogen would

Table 5.21 Summary of the evaluation of the future viability of balancing technologies

	Indicator	Evaluation[a]
Resource availability	Ratio of available reserves to production – height and stability of "period of secure practice"	Reserves-to-production ratio smaller than 60 years (period required for system switch): antimony, chromium, tin, zinc, arsenic, lead, cadmium, copper, zircon oxide, nickel and manganese Decreasing reserves-to-production ratio: yttrium, iron, tin, manganese, bauxite, antimony, cobalt, vanadium, lead, platinum group metals, cadmium, zinc
	Amount of material required for production of technologies	Using the entire worldwide reserves, batteries with a capacity of about 4.9–6.6 TWh_{el} or, if less cobalt is used in lithium-ion batteries, 36 TWh_{el} could theoretically be realised. This is about 2–3 times or, using lithium-ion batteries with less cobalt content, 20 times the estimated capacity required for balancing the energy system in Germany in 2040+. Considering resources instead of reserves allows higher capacities. Using the reserves so that reserve-to-production ratios of at least 60 years are assured, which is currently only possible for cobalt, iron, lithium and vanadium, the theoretical capacities decrease only slightly. The highest relevant change results for cobalt, which decreases by a factor of 2.3
	Amount of reserve base[b]	Resources-to-production ratio below 100 years: antimony, arsenic, tin, chromium, zinc, lead, zircon oxide, cadmium, copper, yttrium, nickel
	Price changes	Price increase from 2001 to 2006 >300%: cadmium, nickel, zinc, copper
	Regional concentration of reserve occurrences	Two countries >70%: platinum group metals, chromium, lithium, vanadium, cobalt
	Regional concentration of delivery and revenues	Two countries >70%: yttrium (China: 99%), platinum, palladium (Russia: 44%), zircon oxide

(continued)

Table 5.21 (continued)

	Indicator	Evaluation[a]
Environmental effects	Environmental external social costs per kWh provided of today's technologies in the 2050 system (human health, crop losses, material damage, loss of biodiversity)	Low for lithium-ion batteries, pumped hydro, electrolyser for hydrogen storage and for photovoltaic and wind with large amounts of full load hours, which may change with less utilisation at over-installation High for battery technologies such as NiMH and lead-acid and gas technologies, even if combined cycle with CCS Values for all, except for gas CC CCS and pumped hydro in non-alpine regions, dominated by effects of SO_2
	Categories of environmental impacts following CML 2001 valuation scheme	Best performance: pumped hydro, electrolyser Lithium-ion batteries similar to electrolyser, but worse in eutrophication and fresh water aquatic ecotoxicity Lead-acid batteries: bad in acidification, fresh water aquatic and terrestrial ecotoxicity, photochemical oxidation Photovoltaics (PV) and wind: high effects in marine aquatic and terrestrial ecotoxicity, (eutrophication: only PV multi-crystalline-Si, Central Europe) Gas technologies: dominating abiotic depletion, ozone layer depletion, global warming, high values in human toxicity, photochemical oxidation, terrestrial ecotoxicity, acidification
Characteristics of the energy supply system	Supply reliability – breakdown and quality	The quality of supply will rise if the right technologies are applied, because this is a major task of the technologies assessed
	Supply reliability – diversity	With the analysed technologies, new options enter the market and diversity increases
	Supply reliability – fair and affordable access	Provided that regulations are designed respectively and respective business models are implemented, access via demand-side management and potential installation and use of decentralised storage units will prospectively be fair and affordable
	Supply reliability – participation	Participation of individuals will prospectively even be asked for in order to realise all potentials
	Risk avoidance – technical risks	Protective measures have to be implemented so that sudden and uncontrolled releases of the stored energy leading to unacceptable impacts are

(continued)

Table 5.21 (continued)

	Indicator	Evaluation[a]
		practically eliminated. Further concessions may be necessary to obtain the acceptance of the local population
	Risk avoidance – marginal environmental risks	The options lithium-ion battery, pumped hydro, hydrogen storage (only electrolyser analysed) and additional photovoltaic or wind offshore plants with high utilisation perform well
	Risk avoidance – risks with potentially unacceptable impacts	In comparison to the other technologies, particularly pumped hydro plants, electrolysers for hydrogen storage, additional photovoltaic (cadmium telluride in southern Europe) and wind power plants perform well
	Open for alternative options	Generally increasing with the technologies if the funding is open for all alternatives

[a] Materials are listed in order of decreasing importance
[b] In 2008

result in about 35 TWh of extra available electrical power. Another possibility would be to implement high storage capacities in other European countries such as Norway or Sweden with higher potentials and then import electricity when needed.

– For load levelling, pumped hydro plants can also be used, but compressed air storage, especially adiabatic concepts, could become an interesting alternative (both less than 5 €ct/kWh achievable). Batteries can also be used for load levelling, although they are more expensive than CAES, and pumped hydro with 8–12 €ct/kWh achievable. They can, however, additionally deliver primary reserve.
– For peak shaving in distribution grids various battery systems are in competition with each other. Assuming the best prognosis, sodium-sulphur (NaS) technologies lead with less than 5 €ct/kWh. They have been commercially in operation for several years in Japan. Today, lead-acid systems are still the most economic systems.

Double-use storage potential and demand-side management for the control of industrial loads, heat pumps and white goods will be important. In addition, electric vehicles and CHP could prove very interesting in the future, with an overall theoretical potential of providing 16–23 GW of storage power. Considering user acceptance, the potential will decrease to about 10 GW. Demand-side management (DSM) is thus an option which will contribute to energy balancing, although the estimated economic benefits of 18 € per household and year are small.

Beside storage options and managing peak demand, the possibility of shutting down wind and solar power plants has to be addressed. In an energy system with

a high share of renewable energies it will be absolutely necessary to have this option available. It is not only necessary from a technical perspective, but also from economical and legal points of view.

An analysis of the future viability of different storage systems reveals that it is necessary to take a closer look at the production processes, which could lead to high emissions of pollutants particularly when minerals are processed. The life cycle screening carried out above shows for instance high impacts for NiMH batteries due to high SO_2 emissions in the nickel production process. In contrast, Li-ion batteries performed quite well. These emissions will prospectively gain importance because the level of CO_2 emissions will already be very low. Resource availability and use of mineral resources must be taken into consideration. In batteries and some other relevant technologies, materials are used that are not sustainable from a reserve-to-production ratio perspective. Also, materials are being used that are regionally highly concentrated, at levels of approximately 70% of known reserves in only two countries. Others being used have high absolute market prices or have experienced relatively high price increases. Of the analysed materials, titanium is unproblematic. There are currently only a few problems associated with lithium, vanadium, arsenic, nickel and zircon oxide. A large-scale use of lithium type, lead-acid and vanadium batteries, however, will require high recycling rates and potentially in the long run, the use of substitutes. With respect to system characteristics, particularly small modular systems are relatively positively evaluated. Large central non-modular technologies, especially when located outside the country, could result in import dependencies and require large efforts to reach sufficient redundancy. They could also be faced with acceptance problems, given public opposition to the large-scale infrastructure development (e.g., grid structures) that could occur. As discussed in Sect. 2.3.2, system change will require participatory decision-making processes if the population is to be won over to the need for change. Furthermore, measures should be implemented to reduce technical risks of sudden uncontrolled releases of power. The development of an electricity system based on a high share of renewable energies will require a mixture of technologies to be able to balance supply and demand needs. Technological improvements and new technologies will be needed. For this, technology neutral funding schemes will be necessary so that no promising options are hampered by lack of sufficient funding.